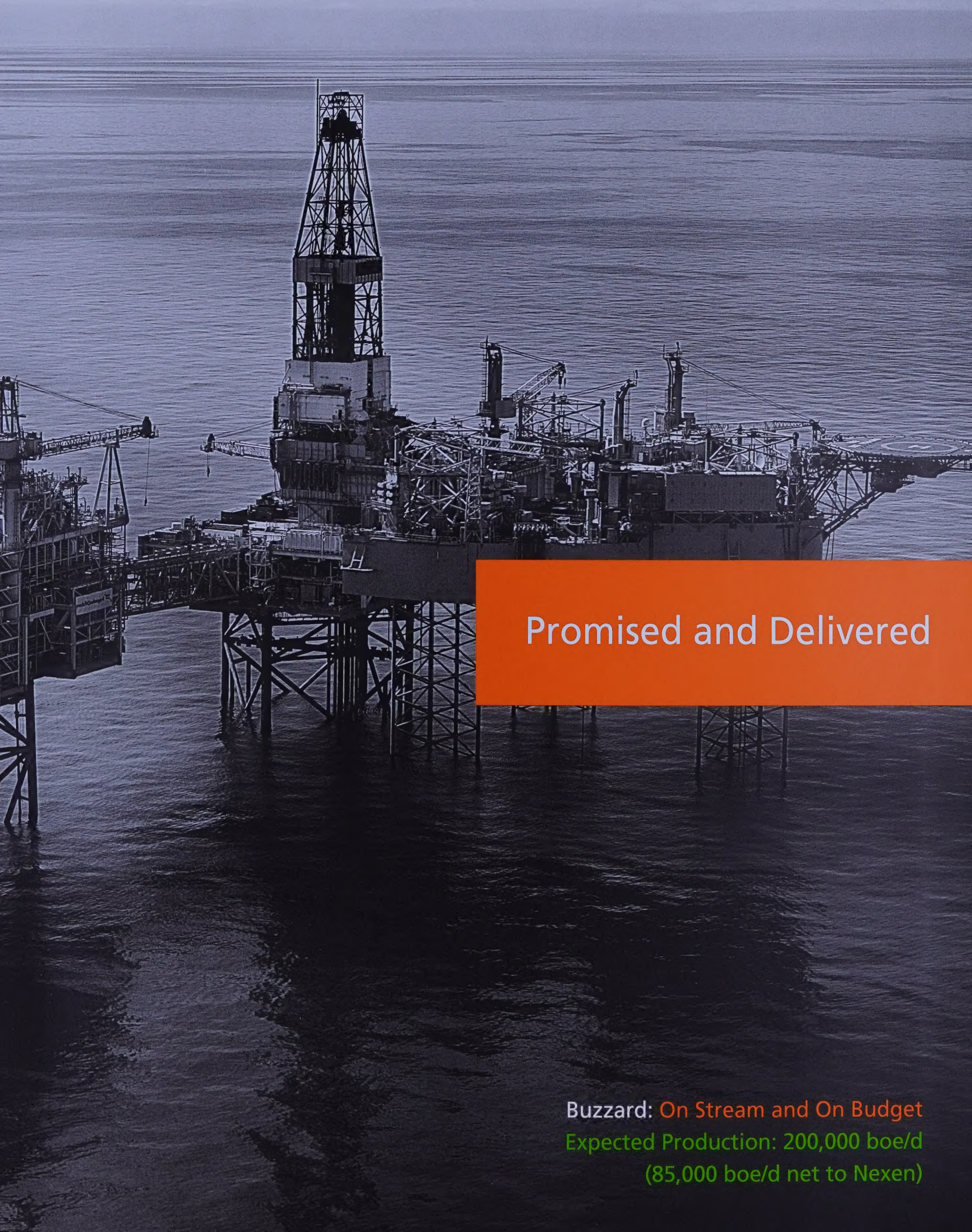
nexen

World-Class CAPACITY

2006 Annual Report


Promised and Delivered
Buzzard: On Stream and On Budget
Expected Production: 200,000 boe/d
(85,000 boe/d net to Nexen)

Charlie Fischer
President and CEO

It takes great people and the right assets to build world-class capacity and deliver extraordinary results. At Nexen, we have both.

President's Review

This is an exciting time for Nexen. For the past few years, we've been developing our world-class assets with the confidence that these projects would result in significant value growth once on stream. I am proud to say that we've delivered on a huge promise—producing first oil from our North Sea Buzzard project this past January.

Buzzard is the most significant project we've developed since bringing Masila on stream in Yemen over a decade ago. Completing the Buzzard development on budget and in just three years was a major accomplishment. It included safely managing more than 17 million staff hours, coordinating hundreds of suppliers and contractors, lifting over 25,000 tonnes of steel and battling harsh North Sea weather conditions.

Buzzard is a world-class asset with more than a billion barrels of oil in place. It is one of the North Sea's largest discoveries in 15 years and is expected to produce approximately 200,000 boe/d (85,000 boe/d net to us) of high-margin production at its peak. In 2007, Buzzard will be the largest contributor to our expected 50% growth in production after royalties, and could help us increase our cash flow by just as much, assuming commodity prices are similar to last year. This growth profile is impressive and makes us an industry leader. Yet there is more value to realize at Nexen beyond Buzzard.

Equally exciting is our oil sands resource and strategy. The Canadian Athabasca oil sands is the world's second largest oil resource and our oil sands projects are in the heart of it. We were an early player in acquiring key landholdings and now have more than five billion barrels of recoverable resource. Our strategy integrates steam-assisted-gravity-drainage (SAGD) with upgrading technology to produce a high-quality synthetic crude oil. More importantly, our process significantly reduces our need to

	2006	2005	2004
Cash Flow from Operations ($ millions)	2,669	2,403	1,942
Cash Flow per Share ($/share)	10.18	9.23	7.55
Net Income ($ millions)	601	1,140	793
Net Income per Share ($/share)	2.29	4.38	3.08
Capital Expenditures ($ millions)	3,330	2,638	1,681

purchase natural gas, a key cost driver in competing technologies. As a result, we expect to develop this vast resource at a significant cost advantage. Over the next decade, we are planning to grow our production here to 120,000 bbls/d using a phased development approach. This allows us to cost-effectively access the resource as we control the pace of expansion and apply learnings to future phases. In 2007, we expect to start up our first phase at Long Lake.

Long Lake is a major development project. In 2006, we completed the SAGD facilities and continued constructing the upgrader, which is now over 80% complete. This involved managing more than 4,000 site contractors every day. Soon we expect to begin injecting steam into the reservoir, followed by bitumen production and start up of the upgrader later in the year. Peak production of approximately 60,000 bbls/d (30,000 bbls/d net to us) of premium synthetic crude is expected by late 2008 or early 2009. While we made significant construction progress in 2006, we experienced an increase in capital costs due largely to high levels of activity in the oil sands. Though this was disappointing, the real value of this project will be realized through our estimated $10/bbl operating cost advantage. Apply this to our five billion barrels of recoverable resource and you can see the value.

While our resource base provides opportunities, it is the innovation and commitment of our people that turns these opportunities into growth.

Our 2006 financial results were impressive. We delivered record cash flow of $2.7 billion or $10.18 per share and net income of $601 million or $2.29 per share. Strong commodity prices and a record contribution from our marketing division helped generate these results. Our annual production of 212,000 boe/d (156,000 boe/d after royalties) was slightly lower than our projected range due to delays at Buzzard, Syncrude and Aspen—all of which are now in production. Buzzard is on stream and ramping up as expected, the Syncrude Stage 3 expansion has added 8,000 bbls/d to our production capacity and the additional development well at Aspen began producing in late December.

In 2006, we carried out our largest capital program ever, managing our base production and investing in future growth. Yemen remains a core asset and is expected to generate 15% of our projected 2007 cash flow. As Masila matures, we continue to manage declines and produce the remaining reserves in the most economical and sustainable manner. In the North Sea, we are gearing up to bring our Ettrick development on stream in 2008—adding an estimated 16,000 boe/d. Offshore West Africa, basic engineering for the Usan field development is complete and tendering of contracts is proceeding. We are eager to formally sanction this project in 2007, as it is projected to add approximately 30,000 bbls/d to our production by 2011. On the exploration front, results continue to be positive. During the year, we drilled two successful wells in the Gulf of Mexico and one in the North Sea. We also continued to appraise our world-class Knotty Head discovery in the Gulf of Mexico, drilling a successful sidetrack well. We are undertaking another exciting global exploration program in 2007 and anticipate new discoveries from the 19 wells planned.

	2006	2005	2004
Production before Royalties (mboe/d)	212	242	250
Production after Royalties (mboe/d)	156	173	174
Proved Reserves [1] (mmboe)	1,049	786	843
Proved + Probable Reserves [1] (mmboe)	1,651	1,621	1,650

1 *Represents our working interest before royalties using year-end pricing and includes our Syncrude reserves.*

We have a number of projects that are expected to generate more value in the future. Our strategy focuses on identifying growth opportunities and moving into these areas early. Our coalbed methane (CBM) project in Canada demonstrates our success with this strategy. We built our CBM land position years ago, before the technology to develop this unconventional resource in the area was proven. We have acquired expertise over the years, and in 2005 we announced the first commercial development in the Mannville coals. Our CBM production is expected to reach 150 mmcf/d by 2011, which should more than double our current Canadian gas production. Building on our success, we are taking this knowledge overseas and evaluating one of the first CBM exploration programs in the UK. We are also an early mover with shale gas in Canada, acquiring a considerable land position in northeast British Columbia last year. The size of the prize here could be substantial—twice that of CBM—and we are excited to begin exploring this potential in 2007. We have also set our sights on exploratory basins offshore Norway where the chances of making a material discovery are high. These examples highlight our diverse portfolio of assets and opportunities that we expect will deliver production growth and shareholder value well into the future.

Our reserve bookings are beginning to reflect the value in our projects. In 2006, we added 341 mmboe of proved reserves, replacing our annual production more than four times over. At year end, proved and probable reserves totalled 1,651 mmboe. However, our total captured resource is significantly higher as our booked reserves reflect only a portion of the resource in our oil sands acreage, CBM leases and undeveloped discoveries like Knotty Head. Including these, you can see the significant capacity we have.

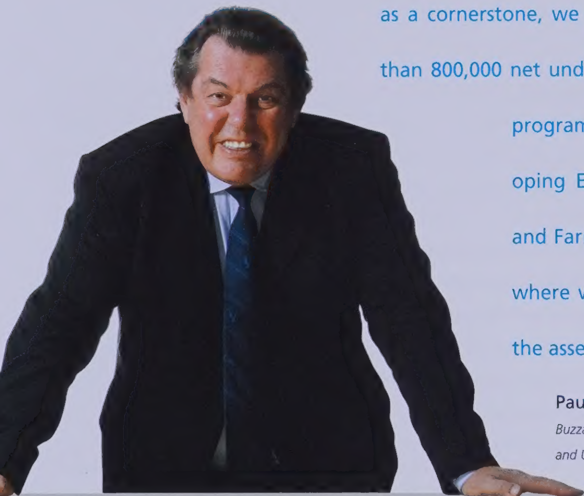
Our ability to deliver is anchored by our corporate values across the organization, from our supportive and participative Board of Directors, to our creative and dedicated employees and management team. We operate in a safe and environmentally responsible manner and last year achieved our best-ever employee/contractor safety performance. This is outstanding given the millions of staff hours worked. I extend my thanks to each employee for their commitment to safety, integrity and excellence.

Externally, we are recognized for our results and the way we do business. Last year, we received several awards highlighted later in this report which reflect our high standards in safety, leadership, social responsibility, reporting and corporate governance. I am proud that Nexen has once again been named one of the 50 best employers in Canada and remains in the Dow Jones Sustainability Index for the sixth year. Our relative market performance is also notable. For the second year in a row, our stock outperformed our North American peers and over the past three years has appreciated by an impressive 270%.

With so much value-added progress at Nexen, we are gearing up for an exceptional future. I am proud to lead a company that stays true to its values, its people and its shareholders. I invite you to learn more about us at our Annual General and Special Meeting in Calgary, Alberta on April 26, 2007.

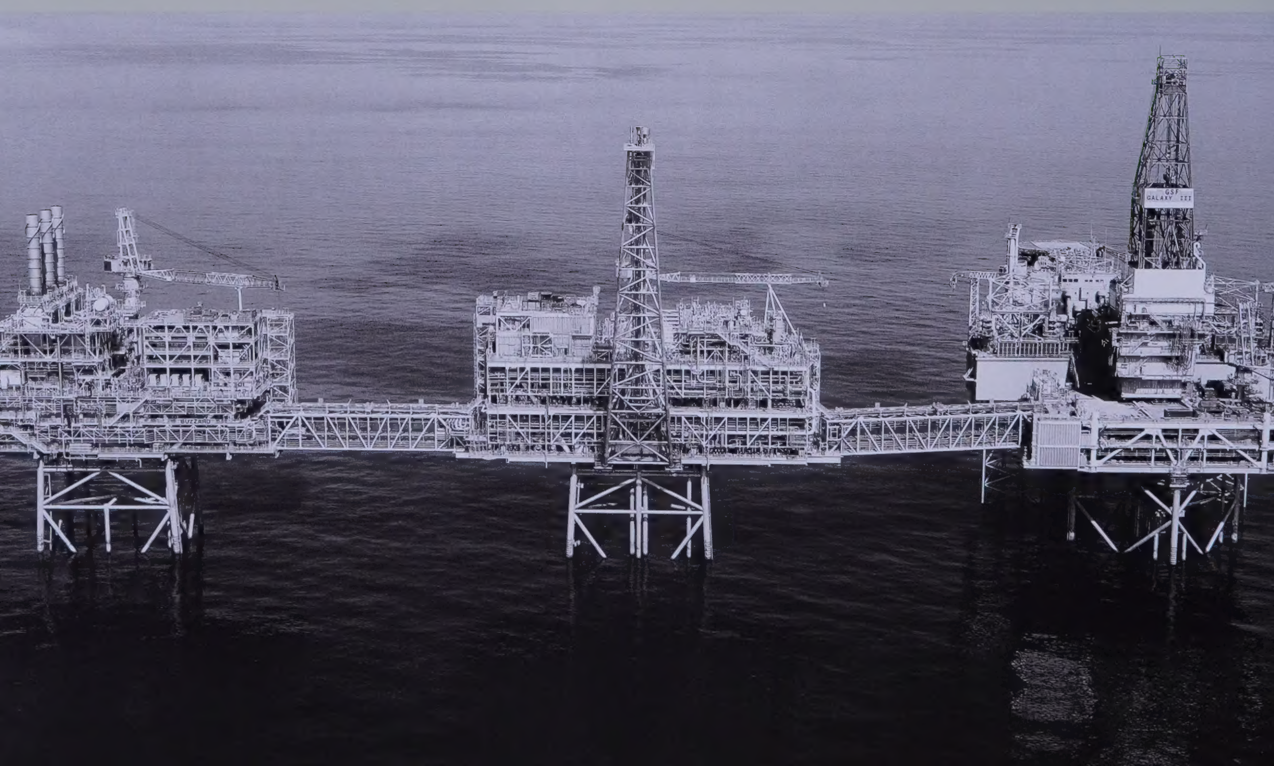
Charlie Fischer
President and CEO
February 26, 2007

Bringing Buzzard on stream was a significant milestone. It is one of the largest projects undertaken at Nexen in terms of size, cost and production volume. With Buzzard ramping up, Long Lake coming on stream and additional production from Syncrude, we are on track to grow production after royalties by 50% in 2007. This is not something many companies can do, and the growth doesn't stop there. With Buzzard as a cornerstone, we have an exciting future in the North Sea. We have more than 800,000 net undeveloped acres and a robust exploration and development program. It includes drilling five exploration wells in 2007, developing Ettrick and optimizing production from our Scott, Telford and Farragon fields. We will also begin exploring offshore Norway where we were recently awarded four blocks. At Nexen, we have the assets and the people to deliver extraordinary results.



Paul Doble
Buzzard General Manager and UK Projects Director

CAPACITY

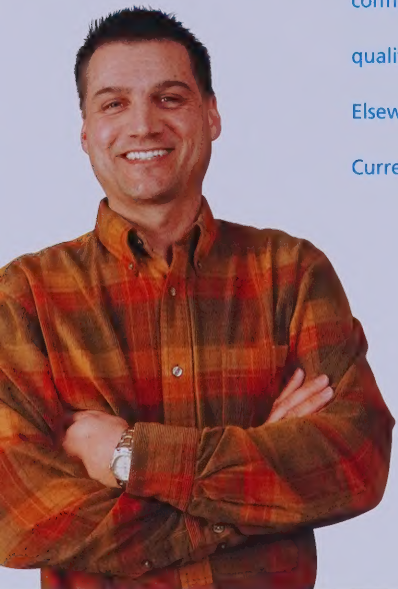


to deliver 50% net production growth

It's very rewarding to work for a company that delivers on its promises and lives its values day in and day out. For the first time ever, our operations at Scott/Telford went 500 days without a lost-time injury. This is a huge accomplishment and shows our commitment to safety.

Kevin Tracy
Field Manager
Scott/Telford

We believe innovation and technology are the keys to developing our long-life resource base. Our oil sands strategy illustrates this best. We've taken conventional technologies commonly used around the world and uniquely configured them. As a result, we have a patented process that will produce higher-quality synthetic crude at much lower operating costs than other oil sands projects. Elsewhere in Canada, we are testing several enhanced heavy oil recovery techniques. Current primary recoveries are about 7%, and with over 2 billion barrels of oil in place on our existing heavy oil lands, even a small increase in recovery factor can have a significant impact. It's a competitive industry out there and our innovative thinking—big and small—gives Nexen an edge.



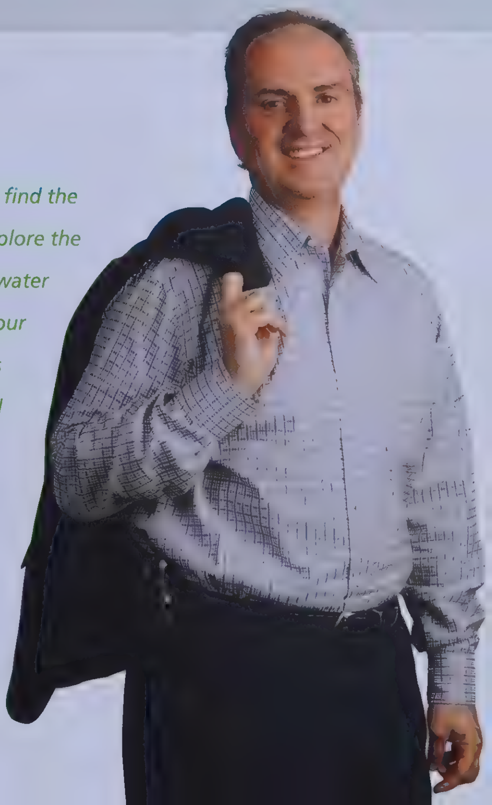
Nolan Palmquist
Operations Manager
Long Lake

CAPACITY

for innovative thinking

"We believe companies that push the envelope on technology will find the big prize. That's why every day we look for innovative ways to explore the Gulf of Mexico. We've been using seismic data to interpret deep-water sub-salt plays and today are considered technical experts among our peers. In fact, we've had a major energy company partner with us for this expertise. A great win for a company our size—all created by innovative thinking."

Brian Reinsborough
Chief Operating Officer
Nexen Petroleum USA



The way we do business is not just a value—it's a defining characteristic of our company. Our mission is to grow value responsibly. To accomplish this, we go beyond regulatory requirements in all areas of our business. In 2006 we invested in our first renewable energy initiative, a wind farm in southern Alberta. At full capacity, it will produce enough green energy to power approximately 25,000 homes. And we continue to invest in the communities where we operate. In Yemen, we sponsor projects that support health, education, civic and community development. This includes awarding scholarships to promising Yemeni students, enabling them to study and graduate from post-secondary education programs in Canada. We are proud of our global reputation to go beyond what is required.

Bill Gourley
Senior Advisor
Community Affairs

CAPACITY

to go beyond

"Nexen is a company that does the right things for the right reasons. I was honoured to accept the Conference Board of Canada/Spencer Stuart National Award in Governance on Nexen's behalf. The award recognizes Nexen's exceptional governance practices, including an innovative approach to discussing governance issues with stakeholders and making improvements. I'm pleased that Nexen's long-term commitment to good governance is being recognized."

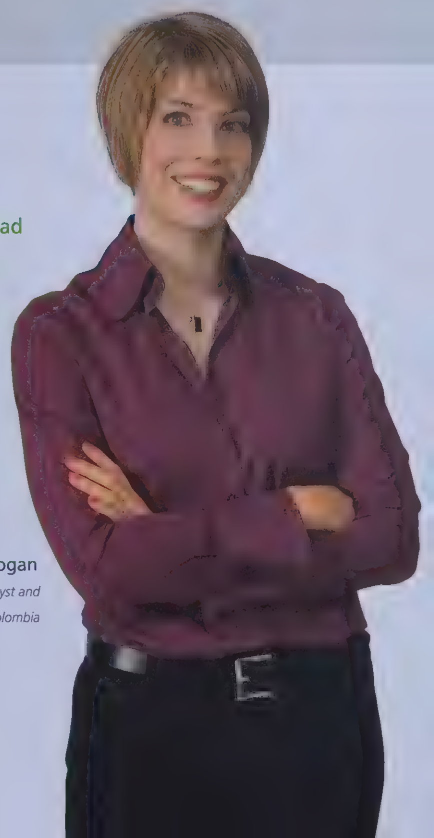
Francis Saville
Chair of the Board

Our future is in the hands of our employees. Whether it's building a new project or working with communities to understand their needs, the dedication and skills of our 3,200 employees worldwide are integral to our success. We recognize the importance of our employees and strive to be an employer of choice. We provide attractive compensation and benefit programs and are constantly seeking feedback to improve. For example in 2006, employees were provided with the opportunity to increase flexibility in their work schedules. We are a company with an exciting future and a suite of world-class assets. This creates tremendous diversity in career opportunities and experiences ranging from the dynamic marketing trading floor to the demanding environment of offshore platforms. At Nexen, we see opportunities. We see commitment. We see value.

Harpal Brar
Manager, Risk Analysis and Reporting
Nexen Marketing

CAPACITY

to build our future



"Nexen is a company rich in opportunity, diversity and leadership. I've had the privilege of working on exciting projects in Canada, Colombia and the UK and all have been successful thanks to the commitment of the people involved. It's fun being part of a team that sets their sights on big things and then provides the tools and encouragement to succeed. Nexen is a well-respected company, operating with integrity and accountability, and I take pride in being part of it."

Heather Rogan
UK Technical Analyst and
Senior Engineer, Colombia

Building Our Future

Our rich and diverse portfolio has the right building blocks to deliver big value to shareholders. Here are the results of our capital investment—both achieved in 2006 and expected in the future.

Achievements in 2006:

- Buzzard development completed and on stream in January 2007
- Syncrude expansion completed, adding 8,000 bbls/d of capacity to us
- New Aspen development well on stream; current field rates approximately 18,000 boe/d
- Long Lake project on track to start up in 2007
- Exploration successes achieved in the Gulf of Mexico and North Sea

Looking ahead, we expect:

2007

- Net production to increase 50% with new volumes from Buzzard, Long Lake and Syncrude
- Buzzard to ramp up to peak rates of 200,000 boe/d (85,000 boe/d net to us)
- Long Lake steam injection to begin, followed by bitumen production and upgrader start up
- Usan development, offshore West Africa, to be formally sanctioned

2008

- Long Lake production to increase to peak rates of 60,000 bbls/d (30,000 bbls/d net to us)
- Ettrick to come on stream, ramping up to approximately 16,000 boe/d net to us
- Knotty Head delineation to continue; additional well to be drilled
- Long Lake Phase 2 to be sanctioned

Beyond

- CBM production to grow to approximately 150 mmcf/d net to us by 2011
- Usan to come on stream, adding approximately 30,000 boe/d net to us by 2011
- Knotty Head development to begin before the end of the decade
- Oil sands production to reach about 120,000 bbls/d net to us over the next decade

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of

THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2006

Commission File Number 1-6702

NEXEN INC.

Incorporated under the Laws of Canada

98-6000202

(I.R.S. Employer Identification No.)

801 – 7th Avenue S.W.

Calgary, Alberta, Canada T2P 3P7

Telephone - (403) 699-4000

Web site - www.nexeninc.com

Securities registered pursuant to Section 12(b) of the Act:

Title	Exchange Registered On
Common shares, no par value	The New York Stock Exchange The Toronto Stock Exchange
Subordinated Securities, due 2043	The New York Stock Exchange The Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes _√_ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ___ No _√_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

Yes _√_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer.

Large accelerated filer _√_ Accelerated filer ___ Non-accelerated filer ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No _√_

On June 30, 2006, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $16.5 billion based on the Toronto Stock Exchange closing price on that date. On January 31, 2007, there were 262,830,108 common shares issued and outstanding.

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Special Note to Canadian Investors — see page 81

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format. Volumes and reserves include Syncrude operations unless otherwise stated.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

/d	=	per day	mboe	=	thousand barrels of oil equivalent
bbl	=	barrel	mmboe	=	million barrels of oil equivalent
mbbls	=	thousand barrels	mcf	=	thousand cubic feet
mmbbls	=	million barrels	mmcf	=	million cubic feet
mmbtu	=	million British thermal units	bcf	=	billion cubic feet
km	=	kilometre	WTI	=	West Texas Intermediate
MW	=	megawatt	NGL	=	natural gas liquid

In this 10-K, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf/1bbl). This conversion may be misleading, particularly if used in isolation, as the 6mcf/1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

The noon-day Canadian to US dollar exchange rates for Cdn $1.00, as reported by the Bank of Canada, were:

(US$)	December 31	Average	High	Low
2002	0.6331	0.6369	0.6618	0.6199
2003	0.7738	0.7135	0.7738	0.6350
2004	0.8308	0.7683	0.8493	0.7159
2005	0.8577	0.8253	0.8690	0.7872
2006	0.8581	0.8818	0.9099	0.8528

On January 31, 2007, the noon-day exchange rate was US $0.8480 for Cdn $1.00.

Electronic copies of our filings with the Securities Exchange Commission (SEC) and the Ontario Securities Commission (OSC) (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, on request, by contacting our investor relations department at 403.699.5931. As soon as reasonably practicable, our filings are made available on our website once they are electronically filed with the SEC and/or the OSC. Alternatively, the SEC and the OSC each maintain a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the OSC.

Operations

We have developed specific capabilities in oil sands, coalbed methane, deep-water technology and international locations. These provide us with world-class capacity for future growth.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 by the combination of the Canadian crude oil, natural gas, sulphur and chemical operations of two subsidiaries of Occidental Petroleum Corporation (Occidental). We've grown from producing 10,700 boe/d before royalties with revenues of $26 million in 1971, to 211,700 boe/d before royalties (including Syncrude production) and revenues of $3.9 billion in 2006. We achieved this growth through exploration success and strategic acquisitions. In more than 30 years of operations, we have been profitable every year, except one, and have been paying quarterly dividends consecutively since 1975.

In the 1970s, we expanded our western Canadian assets and entered the US Gulf of Mexico. We finished this decade with production of approximately 11,000 boe/d before royalties and revenues of $126 million.

In the 1980s, we continued to expand in western Canada by acquiring Canada-Cities Service, Ltd. in 1983. This acquisition doubled our size and included an interest in the Syncrude Joint Venture, our entry into the Athabasca oil sands. Acquisitions of Cities Offshore Production Co. in 1984 and Moore McCormack Energy, Inc. in 1988 established our presence in the Gulf of Mexico. We finished this decade with production of approximately 68,600 boe/d before royalties and revenues of $591 million.

In the 1990s, we had two defining events: discovering oil on the Masila block in Yemen and acquiring Wascana Energy Inc. The first of 17 fields at Masila was discovered in 1991, and Masila has produced more than 940 million barrels since start up in 1993. Our 1997 purchase of Wascana Energy Inc. almost tripled our Canadian production. In 1998, we entered Australia with an interest in the offshore Buffalo field and Nigeria as the operator of the Ejulebe field. Also in 1998, we discovered Ukot on Block OPL-222, offshore Nigeria, the first of several discoveries to date on the block. We finished this decade with production of approximately 239,200 boe/d before royalties and revenues of $1.7 billion.

So far in the 21st century, we have made a number of discoveries, two strategic acquisitions and completed a non-core divestiture program. In 2000, we discovered Gunnison in the deep-water Gulf of Mexico and Guando in Colombia. We joined with Ontario Teachers' Pension Plan Board (Teachers) to acquire Occidental's remaining 29% interest in us. Teachers purchased 20.2 million common shares. We repurchased the remaining 20 million common shares for $605 million, which would have had a value of more than $2.6 billion at year-end 2006. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations and we changed our name to Nexen Inc. from Canadian Occidental Petroleum Ltd. In 2001, we discovered Aspen in the deep-water Gulf of Mexico and signed a joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake in the Athabasca oil sands. In 2002, we discovered Usan, the second discovery on OPL-222, offshore Nigeria. In late 2003, we discovered two fields on Block 51 in Yemen. In 2004, we acquired properties in the UK North Sea, providing us with operatorship of the Buzzard discovery, the producing Scott and Telford fields and 700,000 exploration acres.

We've grown from producing 10,700 boe/d in 1971 to 211,700 boe/d in 2006. In 2007, we expect our net production to grow by 50%.

In 2005, we sold Canadian conventional oil and gas properties producing approximately 18,300 boe/d before royalties and monetized 39% of our chemical business through the initial public offering of the Canexus Income Fund. We also made a potentially significant discovery in the Gulf of Mexico at Knotty Head and commenced commercial development of our first coalbed methane (CBM) project in the Fort Assiniboine area in western Canada. In 2006, we completed our major development project at Buzzard on budget and made significant construction progress at our Long Lake project in the Athabasca oil sands. In early January 2007, Buzzard produced first oil. With Buzzard on stream, followed by Long Lake later in the year, we expect our production after royalties in 2007 to grow by more than 50%, net of declines. Our portfolio of assets, combined with our talented people and an active exploration program, are expected to provide future growth for our company.

For financial reporting purposes, we report on four main segments:

- oil and gas;
- Syncrude;
- energy marketing; and
- chemicals

Our oil and gas operations are broken down geographically into the UK North Sea, US Gulf of Mexico, Canada,

Yemen and Other International (currently Colombia and offshore West Africa). Results from our Long Lake project are included in Canada. Syncrude is our 7.23% interest in the Syncrude Joint Venture. Energy marketing includes our growing crude oil, natural gas, natural gas liquids, ethanol and power marketing business in North America, Europe and southeast Asia. Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda and chlorine through the Canexus Limited Partnership.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 20 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

STRATEGY

Our goal is to grow long-term value for our shareholders. We define value growth as increasing reserves, production, cash flow and net income over the long term. We believe in developing our competitive advantage, which generates opportunities for long-term success in our ever-evolving industry. As conventional basins in North America mature, we have developed specific capabilities in oil sands, coalbed methane (CBM), deep-water technology and international locations. These enable us to focus on specific types of projects, as we transition toward major projects in established basins, exploration in less mature basins and exploitation of unconventional resources.

Today, we are building new sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:

- We are successful deep-water explorers with significant discoveries at Knotty Head in the Gulf of Mexico and at Usan, offshore Nigeria;
- We are skilled project managers with major development projects at Buzzard in the North Sea, and Long Lake in Canada's Athabasca oil sands. In 2006, Buzzard was completed on budget and just days after the original projected start up date. At Long Lake, construction is progressing well and we expect the SAGD production operations to be on stream by the end of the first quarter in 2007, followed by the start up of the upgrader late in the year;
- We are innovative in our application of technology. Long Lake is expected to be the first oil sands project to use gasification technology to significantly reduce the cost of producing bitumen;
- We are an international operator with a proven track record of successful business ventures in Yemen, the United Kingdom, Nigeria, Colombia and Australia; and
- From time to time, we supplement our growth with acquisitions, such as our strategic entry into the UK North Sea in 2004.

The location and scale of our operations often result in an extended period of time from the capture of opportunities to first production and non-linear year-over-year growth in reserves and production. Significant up-front capital investment is often required prior to realizing production and free cash flows. We fund this investment by maximizing cash flow from our producing assets, issuing long-term debt and selling non-core assets into attractive markets.

We are building sustainable businesses with major projects in established basins, exploitation of unconventional resources and exploration.

Our long-term strategy focuses on building capacity by ensuring we have a sufficient inventory of opportunities for future growth. With Buzzard on stream, followed by Long Lake later this year, we expect to deliver significant production growth. In fact, in 2007 we expect our production after royalties to grow by more than 50%, net of declines. However, the growth does not stop there. Beyond 2007, we have a number of opportunities that are expected to provide production growth and create shareholder value well into the next decade. These opportunities include undeveloped discoveries at Knotty Head in the Gulf of Mexico, Usan and Ukot offshore Nigeria, various discoveries in the UK North Sea, together with development of our CBM and additional oil sands leases in Canada.

In creating sustainable businesses, we are committed to good corporate governance and social responsibility. We believe that over the long term, companies that follow sustainable business practices outperform those with narrower priorities. We foster dialogue with stakeholders about our operational opportunities and challenges, from exploration to production to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing their multiple, and sometimes conflicting goals.

UNDERSTANDING THE OIL AND GAS BUSINESS

The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce

the oil or gas, the fiscal terms of the host regime and the price products command in the market based on quality and marketing efforts. Our goal is to extract the maximum value from each barrel of oil equivalent, so every dollar of capital we invest generates an attractive return.

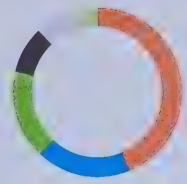
Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices.

Realized prices for our oil and gas products are mainly determined by volatile global crude oil and natural gas markets. With many alternative customers, the loss of any one customer is not expected to have a significant adverse effect on the price of our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products can have a seasonal component that can impact price. In particular, heavy oil is generally in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating. We manage our operations on a country-by-country basis, reflecting differences in the regulatory and competitive environments and risk factors associated with each country.

OIL AND GAS OPERATIONS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, western Canada, Yemen, offshore West Africa and Colombia. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

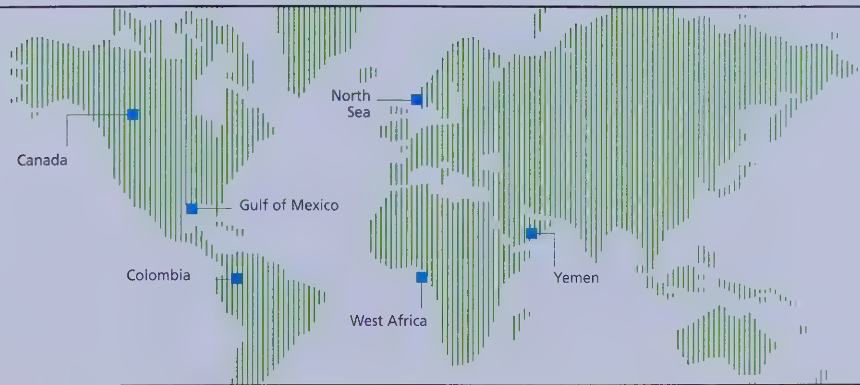
2006 Production before Royalties



In this Form 10-K, we provide estimates of remaining quantities of oil and gas reserves for our various properties. Such estimates are internally prepared. We had 98% of our reserves assessed by independent reserves consultants. Their assessments are performed at varying levels of property aggregation and we work with them to reconcile the differences on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio often differ by significantly more than 10%, either positively or negatively. Refer to the section on Oil and Gas Accounting – Reserves Determination on page 71 for a description of our reserves process.

North Sea—United Kingdom (UK)

The UK is one of our key growth areas. In 2004, we acquired a 43.2% operated interest in the Buzzard development, a 41% operated interest in the Scott field, a 54.3% operated interest in the Telford field, the Scott production platform, interests in several satellite discoveries and more than 700,000 net undeveloped exploration acres for US$2.1 billion. This acquisition established us as a significant regional player with concentrated assets, infrastructure and exploration and development potential for future growth. It added high-margin reserves and production, diversified our worldwide portfolio by adding strong assets in a stable jurisdiction, and complemented our other longer cycle-time projects.



Our UK strategy is focused on exploration and exploitation opportunities near existing infrastructure. We have a number of exploitation opportunities in our existing fields and smaller satellite undeveloped discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford, Buzzard or Ettrick which is currently being developed. As a result, new discoveries could be tied-in relatively quickly, upon success.

During the year, we produced 20,200 boe/d before royalties (20,200 after royalties) in the UK, which was approximately 10% of Nexen's total production. At year end, the UK had proved reserves of 182 mmboe before royalties (182 after royalties) representing about 17% of our total proved oil and gas and Syncrude reserves.

Buzzard Development

The Buzzard field is located in the Outer Moray Firth, central North Sea, about 60 miles northeast of Aberdeen, in 317 feet of water. The field was discovered in 2001 and construction was completed in 2006, with production commencing early January 2007. During the year, we installed the utilities and production topsides, drilled the initial development wells and completed hook-ups and project commissioning. The facilities have the capacity to process up to 200,000 bbls/d of oil and 60 mmcf/d of gas, including the removal of hydrogen sulphide. Based upon recent drilling results, we have experienced more well-to-well variability in the concentration of hydrogen sulphide than previously seen. We expect existing equipment and processes will allow us to manage this variability for at least the first two to three years of production. As we continue to produce and acquire additional reservoir information, we will determine whether additional equipment will ultimately be required. We anticipate the field will be produced through 27 production wells and reservoir pressure will be maintained through an active water-flood program. Buzzard is one of the largest discoveries in the UK North Sea in the past ten years.

Buzzard is on stream and ramping up to estimated peak rates of 85,000 boe/d net to us.

Ettrick Development

We are progressing development of the Ettrick field which is expected to begin producing in the first half of 2008, with our share expected to average approximately 16,000 boe/d (before and after royalties). Development includes drilling three production wells tied back to a leased floating production, storage and off-loading vessel (FPSO) and is approximately

30% complete. Our share of full-cycle development costs is estimated at $460 million. In 2007, we plan to invest $235 million in subsea development including drilling three development wells and one water injection well.

UK Production

Buzzard began producing at the beginning of January 2007. We expect to reach peak gross production rates of approximately 200,000 bbls/d of oil and approximately 30 mmcf/d of gas, with our share about 85,000 boe/d (before and after royalties) in the first half of 2007. Oil from Buzzard is exported via the Forties pipeline to the Grangemouth refinery in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland. In 2007, we plan to invest approximately $130 million to pre-drill and complete 11 future production and injection wells.

Scott and Telford are producing fields with additional exploitation opportunities. Scott, in which we have a 41% working interest, was discovered in 1987 and began producing in September 1993. We have a 54.3% working interest in Telford, which was discovered in 1991 and came on stream in 1996. In 2006, our share of Scott and Telford royalty-free production approximated 16,000 boe/d, of which 80% was oil.

Oil and gas is produced through numerous subsea wells and platform wells. Oil is delivered to the Grangemouth refinery in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in

northeast Scotland. In 2005, the Scott platform underwent a significant maintenance turnaround and facilities upgrade to improve reliability and extend facility life. In 2006, the flare tip and flare tip supporting structure were upgraded. In 2007, we plan to invest approximately $45 million to drill, complete and tie-in three development wells.

Our 2004 UK acquisition included a non-operated interest in Farragon, a small satellite discovery, which was brought on stream in November 2005. In 2006, our 20% share of royalty-free production from Farragon was 3,700 boe/d.

Exploration and Undeveloped Assets

In early 2007, we completed drilling operations at our Golden Eagle prospect and we encountered hydrocarbons. A successful sidetrack was drilled to appraise the accumulation and we are currently evaluating development options. We have a number of smaller discoveries on operated blocks near Scott, Buzzard and third-party facilities as follows:

Field	Interest (%)	Operator Status	Comments
Duart	50	non-operated	discovery near Scott; first oil expected in late 2007
Black Horse	40	operated	discovery near Scott; evaluating development alternatives
Bugle	82	operated	discovery near Scott; well planned for 2007
Dolphin	42	operated	discovery near Scott; evaluating development alternatives
Golden Eagle	34	operated	discovery near Ettrick; evaluating development alternatives
Perth	42	operated	discovery near Scott; evaluating development alternatives
Polecat	40	operated	discovery near Buzzard; evaluating development alternatives
Selkirk	38	operated	appraisal well planned for 2007
Yeoman	50	operated	discovery near Scott; evaluating development alternatives

Development is progressing at Duart. In 2007, we plan to drill a development well and bring the field on stream before year-end. The other discoveries are in various stages of evaluation.

During 2006, we drilled unsuccessful exploration wells at Zanzibar and Black Cat. These wells encountered non-commercial hydrocarbons and were abandoned. In 2007, we expect to drill five exploration and appraisal wells. The offshore drilling rig market is currently tight, however, we have secured drilling rigs for most of our 2007 North Sea exploration and development program.

Coalbed Methane (CBM)

In 2006, we acquired an 80% working interest at an emerging CBM opportunity in the UK. CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by coal in coal deposits rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in reservoir pressure. If the coal deposit is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. If the coal does not produce water and is "dry", gas will be produced from initial development. Water-producing CBM wells in the United States generally show increasing gas production rates for a period of approximately one to three years before gas rates begin to decline.

During 2006, we drilled two exploratory wells at our UK CBM opportunity. The wells encountered all the coal seams expected. In 2007, we plan to continue assessing the potential of this investment by drilling additional wells and production testing them.

Fiscal Terms

UK fiscal terms are favourable. New discoveries pay no royalties and result in cash netbacks that are higher than our company average. Scott is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which isn't expected before 2012. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance. PRT is applicable to fields receiving development consent prior to March 1993. The Buzzard, Telford and Farragon fields are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate is 30% of taxable income. Income from oil and gas activities is also subject to a supplemental charge. The UK government increased this charge from 10% to 20%, effective January 1, 2006. The amount and timing of income taxes payable depends on many factors including price, production, capital investment levels and available tax losses.

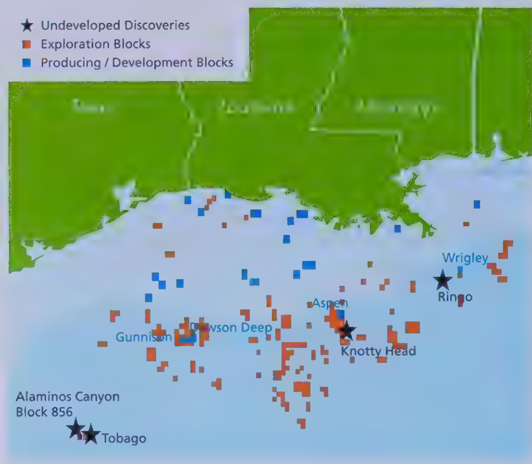
Gulf of Mexico—United States (US)

The Gulf of Mexico is an integral part of our growth strategy. Large discoveries, relatively high success rates, production infrastructure and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. The deep-water prospects generally have multiple sands and high production rates, factors which reduce risk and improve economics. Technology to find, drill, and develop discoveries is rapidly progressing and becoming more cost effective. The deep-water Gulf is relatively near infrastructure and continental US markets, enabling discoveries to be brought on stream in a reasonable period of time.

Our strategy in the Gulf is to explore for new reserves, exploit our existing asset base and acquire assets with upside potential. We focus our exploration program on three strategic play types:

- deep-shelf gas prospects;
- deep-water prospects near existing infrastructure; and
- deep-water, sub-salt plays with potential to become new core areas.

These plays are relatively under-explored, hold potential for large discoveries and have attractive fiscal terms. The shorter-cycle times for shelf gas and deep-water prospects near infrastructure complement the longer-cycle times for deep-water sub-salt plays. Although competition in the Gulf is strong, we expect the availability of expiring acreage over the next few years to provide us with access to additional exploration opportunities.



In 2006, we invested $595 million on exploration and development activities in the Gulf. This resulted in discoveries at Alaminos Canyon Block 856 (Great White West) and Ringo. In 2007, we plan to invest approximately $585 million in the Gulf to further our strategy.

US Production

	2006		2005		2004	
(mboe/d)	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Deep-water	19.6	17.5	24.0	21.5	32.1	28.7
Shallow-water	15.9	13.2	17.6	14.6	22.6	18.8
Total	35.5	30.7	41.6	36.1	54.7	47.5

In 2006, we produced approximately 35,500 boe/d before royalties (30,700 after royalties), representing approximately 17% of Nexen's total production including Syncrude. This was less than expected due to timing delays at Aspen and weather-related disruptions. Weather is a risk in the Gulf of Mexico; specifically, tropical storms and hurricanes can damage facilities, drilling rigs and surrounding infrastructure, interrupt production, and delay exploration and development programs. Storms in 2005 caused damage to third-party infrastructure and as a result, approximately 4,000 boe/d of our pre-storm production was shut-in for nine months of 2006. We carry property and business interruption insurance to mitigate losses caused by adverse weather. During 2006, we received $80 million of insurance proceeds relating to these storms.

At year end, we had proved reserves of 73 mmboe before royalties (63 after royalties) representing about 7% of Nexen's total proved oil and gas and Syncrude reserves. Our production and reserves in the Gulf are primarily concentrated in two deep-water and five shallow-water areas. We operate most of this production.

Deep-Water Production

The majority of our deep-water production comes from our 100%-operated Aspen field and 30% non-operated Gunnison field. Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the Shell-operated Bullwinkle platform 16 miles away. Production began in December 2002 and we achieved payout on our full investment in Aspen in January 2005. Our share of 2006 production before royalties was approximately 8,900 boe/d (8,000 after royalties). In 2006, we drilled an additional development well. This well came on stream in late December. Based on results from this well, we see additional opportunities in the Aspen field and are currently sidetracking the Aspen 1 well to exploit deeper sands. We expect our 2007 production from the Aspen field to average between 15,000 and 20,000 boe/d.

The Wrigley discovery is expected to begin producing in early 2007.

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in December 2003 through our truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas. We achieved payout on Gunnison in December 2005, just two years after first production. In 2006, our share of production before royalties was approximately 10,600 boe/d (9,300 after royalties). Our Gunnison SPAR production facility has excess capacity, leaving room for growth from exploration and processing of third-party volumes. In 2006, we completed the tie-in of our 15% non-operated Dawson Deep discovery to the Gunnison SPAR.

Shallow-Water Production

Our shelf producing assets are offshore Louisiana, primarily in five 100%-owned field areas: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 302/321/339/340, and Vermilion 76 (consisting of Blocks 65, 66 and 67). We continue to exploit these assets and look for other opportunities on the shelf. Most of our 2006 shelf activities focused on development drilling at Eugene Island 258/259 and Eugene Island 295.

Exploration and Undeveloped Assets

Our exploration program in the Gulf of Mexico continues to produce new discoveries. In 2006, we had discoveries at Alaminos Canyon Block 856 (Great White West) and Ringo. We are currently evaluating development options for both of these discoveries. During the year, we also drilled a successful sidetrack well on our 2005 Knotty Head discovery. We are currently proceeding with facility and subsurface studies. Access to deep-water rigs remains limited and we continue to work with partners to find a rig to complete the appraisal of the field. Our undeveloped deep-water discoveries include:

Well	Interest (%)	Operator Status	Comments
Wrigley	50	non-operated	development underway; expected to begin producing in early 2007
Alaminos Canyon Block 856	30	non-operated	evaluating development alternatives
Tobago	10	non-operated	development approved; expected to begin producing in 2009
Knotty Head	25	operated	further appraisal required
Ringo	50	non-operated	additional appraisal well to be drilled in 2007

During the year, we drilled dry holes at Pathfinder, West Cameron 135, West Cameron 109, Eugene Island 19 and Vermilion 65. We increased our deep-water undeveloped land position by 20 blocks to over 200 blocks and expect this acreage and future exploration opportunities to position us well for continued growth. In 2007, we plan to tie-in our Wrigley discovery to a third-party facility. We also plan to drill nine exploration wells (four in the deep water and five on the shelf) and have drilling rigs secured for more than half of these wells. We are actively working with partners to find rigs for the remainder. In 2005, we committed to a deep-water drilling contract, which provides us with access to a new-build fifth generation dynamically positioned semi-submersible drilling rig for two years over a three-and-a-half year period. We expect this new rig to be available in mid 2009.

Fiscal Terms

In 2006, royalty rates on our US production averaged 16.6% for shallow-water volumes and 11.2% for deep-water volumes. The US government has proposed to increase royalty rates from 12.5% to 16.7% for new deep-water leases awarded after July 2007. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmboe of production. However, we may be subject to royalties at Gunnison if annual commodity prices are higher than threshold prices set by the US Department of the Interior's Minerals Management Service (MMS). The oil and gas industry is currently litigating the enforceability of these price thresholds. In 2006, commodity prices exceeded these thresholds, and we were assessed a royalty at Gunnison of 12.5% by the MMS. If the litigation is not successful, royalties that we have accrued on our Gunnison production will be payable. Our Aspen field is not subject to the minimum price threshold, however, the US government has proposed legislation to include minimum threshold prices for deep-water leases granted in 1998 and 1999. If the legislation is approved, our Aspen field could be subject to a 12.5% government royalty on production after October 1, 2006. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0% to 12%

Canada

Our strategy in Canada is to bring our new growth developments into production while we maximize value from our established operations. In 2005, we disposed of approximately 18,300 boe/d before royalties of production, comprising approximately 60% oil and 40% gas. The assets we retained have upside potential for continued conventional development and enhanced recovery with advancements in extraction technology. During the year, we produced 38,000 boe/d before royalties (31,000 after royalties), which was approximately 18% of Nexen's total production including Syncrude. At year end 2006, proved reserves (including bitumen and excluding Syncrude) of 364 mmboe before royalties (319 after royalties) were approximately 35% of our total proved oil and gas and Syncrude reserves.

In Canada, we are increasing our capacity by focusing on unconventional resources such as oil sands, CBM and enhanced oil recovery.

Our remaining Canadian conventional assets comprise heavy oil production in east-central Alberta and west-central Saskatchewan, and natural gas near Calgary and in southern Alberta and Saskatchewan. We operate most of our producing properties and hold 1.1 million net acres of undeveloped land across western Canada. These assets provide predictable production volumes and earnings while we advance the following initiatives for future growth:

- Athabasca oil sands—to produce and upgrade bitumen into synthetic crude;
- enhanced oil recovery (EOR)—to increase recovery in our heavy oil fields; and
- coalbed methane (CBM)—to extract natural gas primarily from Upper Mannville coals.

In 2006, we invested $1,609 million in Canada; $1,416 million into these growth initiatives. In 2007, we plan to invest approximately $1,070 million; $944 million in these initiatives.

Athabasca Oil Sands

The Athabasca oil sands in northeast Alberta is a key growth area for Nexen. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our Long Lake project involves integrating steam-assisted-gravity-drainage (SAGD) bitumen production with field upgrading technology to produce a premium synthetic crude oil that significantly reduces our need to purchase natural gas. We also have a 7.23% investment in the Syncrude oil sands mining operation.

Long Lake Project

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake property using SAGD for bitumen production and field upgrading using the proprietary OrCrude™ process. OrCrude™ is a technology to which OPTI has the exclusive Canadian license. We acquired the exclusive right to use this technology with OPTI, within approximately 100 miles of Long Lake, and the right to use the technology independently elsewhere in the world.

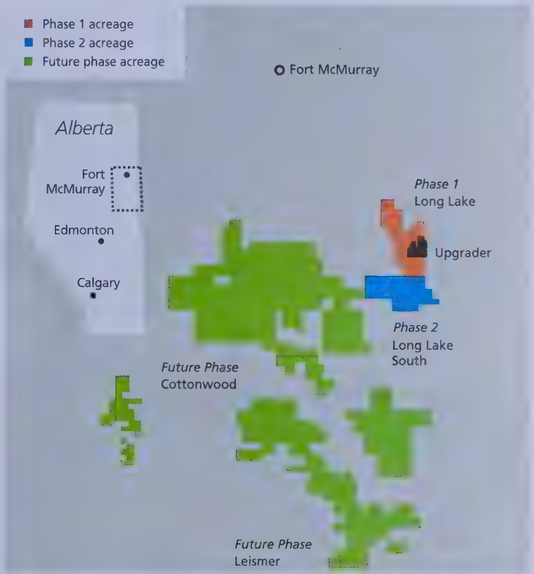
We operate the Long Lake lease bitumen extraction process and are responsible for constructing, developing and operating the SAGD project. OPTI is responsible for the design, construction and operation of the upgrader. We share equally in all project reserves, production, operating and capital costs.

SAGD and Upgrader Integration

SAGD involves drilling two parallel horizontal wells, generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude is upgraded to light (39° API) premium synthetic sweet crude oil, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel source, and as a source for hydrogen required in the hydrocracker. The gas is also to be burned in a co-generation plant to produce steam for the SAGD operations and for electricity to be used on-site and sold to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is about 90% compared to 75% for a typical bitumen-fed coker, which we expect will provide us with an approximate $10/bbl operating cost advantage.

Our Strategic Advantage

Our SAGD and upgrading integration enables us to overcome three main economic hurdles of SAGD bitumen production: 1) the high cost of natural gas; 2) the cost and availability of diluent; and 3) the realized price of bitumen. With synthetic gas from the asphaltenes as a fuel source, we have little need to purchase additional natural gas. With the upgrading facilities on site, expensive diluent is not required

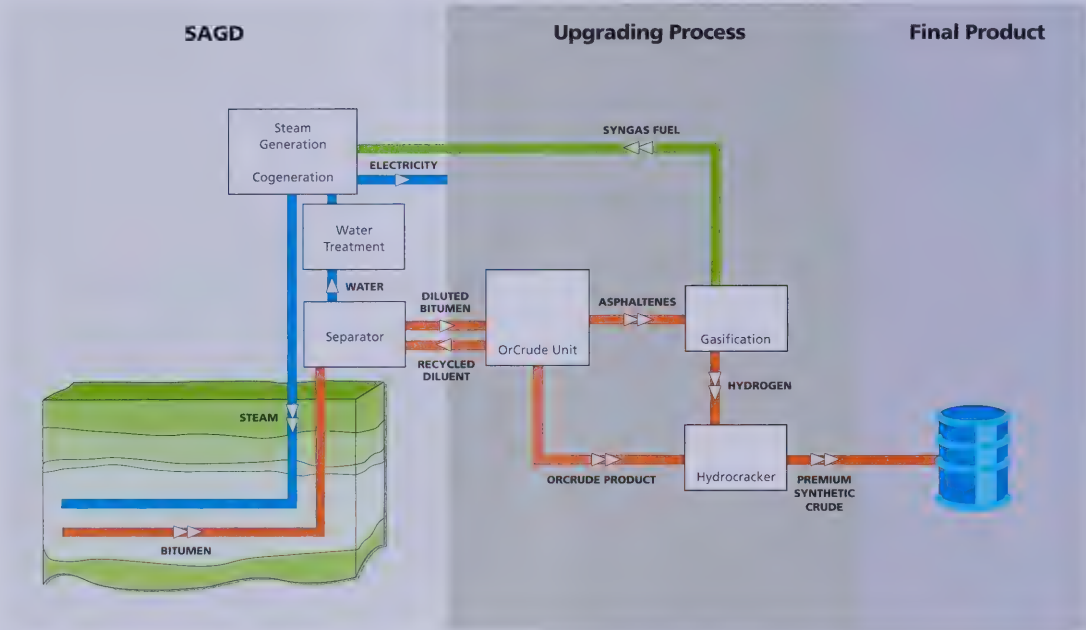


to transport the bitumen to market. And, by upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands light-sweet crude oil premium pricing.

We expect our integrated oil sands strategy will provide us with an approximate $10/bbl operating cost advantage.

Project Milestones and Costs

The Long Lake project received regulatory approval in 2003 and Nexen board approval in 2004. Field construction on the SAGD and upgrader facilities began in 2004. In 2006, we substantially completed module and site construction of the SAGD facilities. Steam injection is expected to commence at the end of the first quarter of 2007, with bitumen production expected to ramp up to peak rates over a 12 to 24 month period. For the first six months of SAGD operation, we will largely be heating the reservoir. During this period, steam to oil ratios will be high but will decline with time as bitumen production ramps up to our target rates. Depending on our actual start up date and the amount of downtime at our facilities, we expect bitumen production before royalties to reach between 35,000 and 45,000 bbls/d (between 17,500 and 22,500 bbls/d net to our share) by the end of 2007, with a steam-to-oil



ratio of between 3.5 and 4.0. We expect the steam-to-oil ratio to average approximately 3.0 over the long-term.

Long Lake is on track for start up in 2007 and expected to reach peak production of about 60,000 bbls/d (30,000 bbls/d net) of premium synthetic crude by late 2008 or early 2009.

Upgrader module fabrication is largely complete and over 95% of the modules are on site. Construction of the upgrader is approximately 80% complete and start up is scheduled for late 2007. Peak output of premium synthetic crude oil is expected within 6 to 18 months of upgrader start up and we expect to exit 2007 with synthetic production rates of between 28,000 and 36,000 bbls/d (between 14,000 and 18,000 bbls/d net to our share). Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (30,000 bbls/d net to our share) of premium synthetic crude, which we expect to reach by late 2008 or early 2009. We also expect production to be maintained over the project's life, estimated at 40 years, by periodically drilling additional SAGD well-pairs.

In 2006, we invested $1,050 million at Long Lake and expect to invest approximately $500 million in 2007. The capital cost estimate when our board sanctioned the project in February 2004 was $3.4 billion ($1.7 billion net). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to ensure certainty and reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million ($49 million net). In early 2006, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million ($180 million net). These scope changes increased the estimated project cost to $3.8 billion ($1.9 billion net). While construction progress has been significant, high activity in the oil sands is placing ongoing pressure on the costs of labour and services. In addition, labour productivity has been lower than anticipated, requiring a larger workforce to maintain progress. As a result, the projected costs of Long Lake have increased from $3.8 billion to $4.6 billion ($1.9 billion to $2.3 billion net). Although we are seeing pressure on capital costs, we expect to benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average between $12/bbl and $14/bbl, substantially lower than coking upgrading. We expect ongoing capital to average between $3/bbl and $4/bbl. The capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

Future Phases

We have approximately 240,000 net acres of bitumen-prone lands in the Athabasca region and plan to acquire more. We plan to continue developing our bitumen lands in a phased manner using our integrated upgrading strategy. In 2005, we announced our plan to duplicate Long Lake by developing Phase 2. In 2006, we invested $119 million for future phases and in 2007, we plan to invest approximately $170 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for these phases. Phase 2 SAGD production is expected to be on stream by late 2011, with upgrader start up by the second half of 2012, followed by additional phases every two years or three years. Each phase will leverage the knowledge and experience gained from successfully developing Long Lake and subsequent projects will be similar in size and design. By keeping the core team in place and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

Phase 2 SAGD production is expected to be on stream by late 2011 followed by upgrader start up in 2012.

Reserves Recognition

Under SEC rules and regulations, we are required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil that we will produce and sell. The economic recoverability of bitumen reserves is sensitive to natural gas prices, diluent costs and light/heavy differentials, risks that our integrated project has been designed to virtually eliminate. At December 31, 2006, we recognized proved bitumen reserves of 246 mmboe before royalties (219 after royalties) for our Long Lake project, representing about 23% of Nexen's total proved oil and gas and Syncrude reserves before royalties.

Heavy Oil

Approximately 52% of our Canadian conventional production is heavy oil. Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also receives a lower price than light oil, as more expensive and complex refineries are required to refine the heavy crude into higher-value petroleum products.

Our heavy oil operations are in east-central Alberta and west-central Saskatchewan. To maximize heavy oil returns, it is important to manage capital and operating costs. Our large production base and existing infrastructure are advantageous to us in managing these costs. In 2007, we plan to continue exploiting our existing fields through drilling and optimizing operations.

Enhanced Oil Recovery

Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs, leaving substantial amounts of oil in the ground. This creates an opportunity to increase recovery factors by applying new technology. We are continuing to research various technologies to increase our heavy oil recoveries with several ongoing pilot projects in west-central Saskatchewan.

Natural Gas

Approximately 48% of our Canadian production is natural gas extracted primarily from shallow sweet reservoirs in southern Alberta and Saskatchewan and from sour gas reservoirs near Calgary. In general, shallower gas targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulfide. We have been producing sour natural gas from our Balzac field northeast of Calgary since 1961. This sour gas is processed through our operated Balzac plant.

Coalbed Methane (CBM)

In 2005, we approved commercial CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area. Our CBM pilot at Corbett in the Fort Assiniboine area of central Alberta has established techniques to produce natural gas from water saturated Upper Mannville coals. These coals are generally deeper than the Horseshoe Canyon "dry coal" play, which is also being commercially developed in Alberta. We established commerciality of CBM production from the Upper Mannville coals in 2005 by applying horizontal well technology. Commercial production rates and reduced de-watering time has enabled us to confidently develop these coals.

In 2006, we invested approximately $237 million in exploration and development activities. We have a long-term view of this business and plan to increase our CBM production to at least 150 mmcf/d by 2011, more than doubling our current Canadian natural gas production. At the end of 2006, we held more than 700 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. We have also established positions in other prospective CBM areas of Alberta. In 2007, we plan to invest $200 million to develop 98 gross (41 net) sections using single and multi-leg horizontal wells. In addition to our development at Fort Assiniboine, we will continue to evaluate other Mannville and Horseshoe Canyon CBM prospects and pursue new CBM opportunities in 2007.

Shale Gas

As part of our growth strategy in unconventional Canadian resource plays, we acquired over 100 sections of land in an emerging shale gas play in western Canada in 2006. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Currently, the United States is the largest producer of shale gas. In 2007, we plan to initiate a drilling and evaluation program to demonstrate the feasibility of this resource.

Fiscal Terms

In Canada, we pay royalties ranging from 15% to 40% on production from lands owned by the federal and provincial governments. Some provinces also impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to crown royalties of 3.3%, which is reduced to 1.85% for wells completed after October 1, 2002.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2006, legislation was passed to reduce the federal corporate income tax rate on income from Canadian oil and gas activities from 24% to 19% by 2010.

For our oil sands projects, we elected to pay royalties based on bitumen production, which includes a 1% royalty on gross revenue until all costs have been recovered, at which time the royalty changes to 25% on net revenue. With the combination of low royalties, our expected operating cost advantage and a premium product, our oil sands financial returns are expected to be attractive relative to other oil sands projects.

Middle East—Yemen

Yemen has been our most significant international region since we first began production at Masila in 1993. We operate the country's largest oil project and have developed excellent relationships with the government and local communities. Our success and reputation in Yemen opens doors elsewhere in the Middle East and around the world.

Although our Masila fields have matured, we expect to generate approximately 20% of the total project cash flow from the remaining proved resources.

Our strategy is to maximize the value from our existing blocks, while we continue to search for new reservoirs in deeper horizons. We have two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2006, we produced 92,900 bbls/d of oil before royalties (51,800 after royalties), representing approximately 44% of Nexen's total production and 32% of 2006 cash flow. Proved reserves of 66 mmboe before royalties (38 after royalties) comprise approximately 6% of Nexen's total proved oil and gas and Syncrude reserves before royalties.

Masila Block (Block 14)

We have a 52% working interest in and operate the Masila project. Our share of 2006 production was 70,300 bbls/d before royalties (35,500 after royalties). After more than 10 years of growth, our Masila fields have matured, but significant value still remains. As a result of the Production Sharing Agreement (PSA) terms that govern Masila production, we still expect to generate approximately 20% of the total project free cash flow from the remaining proved reserves recoverable before the PSA expires in 2011.

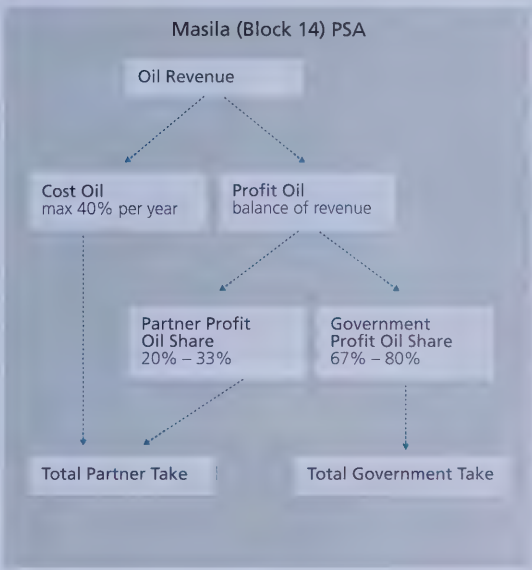
The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993, with the first lifting of oil in August 1993. Masila Blend oil averages 32° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations.

Production is collected at our Central Processing Facility (CPF) where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal and shipped to customers primarily in Asia.

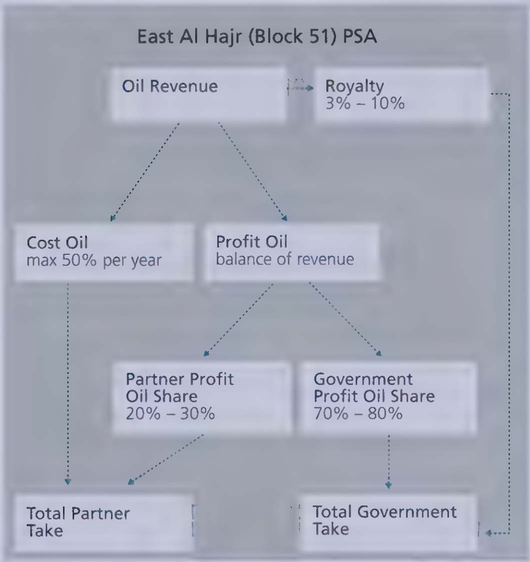
We are managing the pace of our drilling program to ensure we recover the remaining reserves in the most efficient, cost-effective manner. In 2007, we plan to invest approximately $55 million to drill 14 wells.

The PSA governing Masila production was signed in 1987 between the Government of Yemen and the Masila joint venture partners (Masila Partners), including Nexen. Under the PSA, we have the right to produce oil from Masila into 2011 and to negotiate a five-year extension. Production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all exploration, development, and operating costs that are funded by the Masila Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for 4 years
Development	16.7% per year for 6 years



The remaining production is profit oil that is shared between the Masila Partners and the Government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20% to 33%. The structure of the agreement moderates the impact on Masila Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the Government. At current production, the Government is entitled to approximately 73% of the profit oil, which includes a component for Yemen income taxes payable by the Masila Partners at a rate of 35%. In 2006, the Masila Partners' share of production, including recovery of past costs, was approximately 37%.



East Al Hajr Block (Block 51)

We have an 87.5% working interest and operate Block 51. This block is governed by a PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners): The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures. Our effective interest is 100% and for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. We recognize both the Government's share and TYCO's share of profit oil under the PSA as royalties and taxes consistent with our treatment of our Masila operations. The PSA expires in 2023, and we have the right to negotiate a five-year extension. Under the terms of the PSA, the EAH Partners pay a royalty ranging from 3% to 10% to the Government depending on production volumes. The remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen. Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% per year, declining balance
Development	75% per year, declining balance

The remaining production is profit oil that is shared between the EAH Partners and the Government on a sliding scale based on production rates. The EAH Partners' share of profit oil ranges from 20% to 30%. The Government's share of profit oil includes a component for Yemen income taxes payable by the EAH Partners at a rate of 35%. In 2006, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 61%.

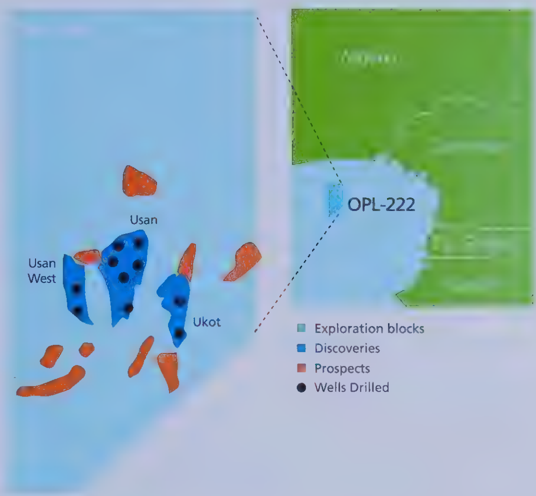
The first successful exploratory well was drilled at BAK-A in 2003, with BAK-B discovered shortly after. Block 51 development began in 2004 and includes a CPF, gathering system and a 22-km tieback to our Masila export pipeline. Production began in November 2004 and we achieved payout on the project in the first quarter of 2006. During the year, production averaged 22,600 bbls/d before royalties (16,300 after royalties).

We achieved payout on Block 51 in the first quarter of 2006.

In 2006, we drilled three exploration wells on the block and two of these wells were abandoned. In 2007, we plan to invest approximately $80 million to drill nine development wells, construct additional facilities and continue exploring with three exploration wells.

Offshore West Africa

Offshore West Africa is a growing core area where we already have discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to explore and develop our portfolio for medium- to long-term growth.



Nigeria

Block OPL-222

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which includes 448,000 acres and is approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. The ongoing appraisal of the block indicates significant hydrocarbon accumulations based on the drilling results outlined below:

Year	Well	Location	Results
1998	Ukot-1	Ukot field discovery well	encountered three oil-bearing intervals and flowed at restricted rate of 13,900 bbls/d from two intervals
2002	Usan-1	Usan field discovery well	encountered several oil-bearing intervals and flowed at restricted rate of 5,000 bbls/d from one interval
2003	Usan-2	3 km west of discovery	appraised up-dip portion of the fault block
2003	Usan-3	2 km northwest of discovery	appraised separate fault block and flowed at restricted rate of 5,600 bbls/d from one interval
2003	Ukot-2	3.5 km south of discovery	encountered three oil-bearing intervals
2003	Usan-4	5 km south of discovery	flowed at restricted rate of 4,400 bbls/d from first interval and 6,300 bbls/d from second interval
2004	Usan-5	6 km west of discovery	sampled oil in several intervals
2004	Usan-6	4 km south of Usan-5	flowed at restricted rate of 5,800 bbls/d from one interval
2005	Usan-7	9 km southwest of discovery	confirmed an eastern extension of the field
2005	Usan-8	3 km southwest of discovery	confirmed an eastern extension of the field

Appraisal of this field is complete. The Nigerian authorities have provisionally approved the preliminary Usan field development plan. We expect the Usan development to be formally sanctioned in 2007, with first production as early as 2010.

Usan is expected to be producing by 2011, adding about 30,000 bbls/d to our production.

The development will include a FPSO with storage capacity of two million barrels, capable of handling peak production rates of 160,000 bbls/d of oil. In 2007, we plan to invest approximately $140 million to progress development by completing our cost estimate. We have a 20% interest in this development program. Proved reserves of 30 mmboe before royalties (25 after royalties) comprise approximately 3% of Nexen's total proved oil and gas and Syncrude reserves.

In 2006, we drilled the deep-water Ukot South well. This well was unsuccessful and the capital costs were expensed.

Block OML-115

We relinquished this block during the year.

Block OML-109—Ejulebe

In 2005, we sold our producing assets and terminated our contractual interest in this block.

Equatorial Guinea—Block K

We relinquished this block during the year.

Other International

Colombia

Boqueron Block—Guando

In 2000, we made our first discovery at Guando on our 20% non-operated Boqueron Block. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Our share of 2006 production averaged 6,300 bbls/d before royalties (5,700 after royalties), about 3% of Nexen's total production including Syncrude.

Production from Guando is subject to a 5% to 25% royalty depending on daily production. In 2006, legislation was introduced to reduce the corporate income tax rate from 38.5% in 2006 to 34% in 2007, and to 33% in 2008 and future years.

Exploration Blocks

We have interests in three exploration blocks in the Upper Magdalena Basin. Villarrica was acquired in 2000, El Queso in 2003 and Boqueron Deep in 2003. In 2005, we relinquished the Villarrica Block and acquired the Villarrica Norte Block under improved fiscal terms. In 2006, we drilled a well on the El Queso block which we are currently evaluating. We are currently participating in a well on Boqueron Deep and plan to drill a well on Villarrica Norte later in 2007. In addition, we are assessing potential drilling opportunities in other areas of the Upper Magdelena Basin.

Norway

As part of our growth strategy in the North Sea, we participated in the 2006 bid round for exploration rights offshore Norway and were awarded interests in four licenses in early 2007. In 2007, we expect to invest approximately $30 million in additional seismic and geologic studies there.

Australia—Buffalo

Field abandonment began in November 2004 and was completed in 2005.

RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Oil and Gas Acreage

	2006					
	Developed		Undeveloped [1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Yemen [2]	50	29	756	628	806	657
Canada	781	578	2,081	1,095	2,862	1,673
United States	183	103	1,396	650	1,579	753
United Kingdom	83	27	1,822	1,031	1,905	1,058
Colombia [4]	1	–	604	463	605	463
Nigeria [2,3]	–	–	448	90	448	90
Total	**1,098**	**737**	**7,107**	**3,957**	**8,205**	**4,694**

Notes.

1 *Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.*

2 *The acreage is covered by production sharing contracts.*

3 *The acreage is covered by a joint venture agreement.*

4 *The acreage is covered by an association contract.*

Producing Oil and Gas Wells

	2006					
	Oil		Gas		Total	
(number of wells)	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Yemen	428	249	–	–	428	249
Canada	2,196	1,519	2,627	2,279	4,823	3,798
United States	191	91	199	138	390	229
United Kingdom	39	17	–	–	39	17
Colombia	91	19	–	–	91	19
Total	**2,945**	**1,895**	**2,826**	**2,417**	**5,771**	**4,312**

Notes:

1 Gross wells are the total number of wells in which we own an interest.

2 Net wells are the sum of fractional interests owned in gross wells.

Drilling Activity

	2006						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Yemen	3.0	5.5	8.5	36.0	1.0	37.0	45.5
Canada	35.4	2.2	37.6	214.3	0.7	215.0	252.6
United States	1.6	2.1	3.7	8.3	2.0	10.3	14.0
United Kingdom	0.8	1.7	2.5	5.5	–	5.5	8.0
Colombia	–	–	–	2.0	–	2.0	2.0
Nigeria	–	0.2	0.2	–	–	–	0.2
Total	**40.8**	**11.7**	**52.5**	**266.1**	**3.7**	**269.8**	**322.3**

	2005						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Yemen	0.5	4.6	5.1	33.0	1.6	34.6	39.7
Canada	32.2	8.0	40.2	198.9	0.5	199.4	239.6
United States	–	0.6	0.6	7.2	1.0	8.2	8.8
United Kingdom	0.5	2.1	2.6	1.5	–	1.5	4.1
Colombia	–	–	–	1.8	–	1.8	1.8
Nigeria	0.4	0.2	0.6	–	–	–	0.6
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
Total	**33.6**	**16.0**	**49.6**	**242.4**	**3.1**	**245.5**	**295.1**

	2004						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Yemen	–	2.0	2.0	37.3	0.5	37.8	39.8
Canada	13.4	1.0	14.4	202.9	–	202.9	217.3
United States	0.3	1.8	2.1	11.0	1.0	12.0	14.1
United Kingdom	–	–	–	–	–	–	–
Colombia	–	–	–	7.0	–	7.0	7.0
Nigeria	0.4	1.0	1.4	–	–	–	1.4
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
Total	**14.1**	**6.3**	**20.4**	**258.2**	**1.5**	**259.7**	**280.1**

Wells in Progress

At December 31, 2006, we were drilling 5 wells in Yemen (3.6 net), 5 wells in Canada (5 net), 2 wells in the United States (1.6 net), 3 wells in the United Kingdom (1.6 net), and 1 well in Colombia (0.5 net).

Net Sales by Product from Continuing Oil and Gas Operations (including Syncrude)

(Cdn$ millions)	2006	2005	2004
Conventional Crude Oil and Natural Gas Liquids (NGLs)	2,479	2,438	1,697
Synthetic Crude Oil	446	397	321
Natural Gas	553	671	534
Total	**3,478**	**3,506**	**2,552**

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 84% of our oil and gas net sales, while natural gas represents the remaining 16%.

Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price [1]			Average Production Cost [1]		
	2006	2005	2004	2006	2005	2004
Crude Oil and NGLs (Cdn$/bbl)						
Yemen	71.57	62.07	47.59	8.11	6.75	5.64
Canada [2]	42.79	40.51	36.60	15.50	14.01	11.76
United States	65.80	57.63	46.60	9.45	7.33	6.09
United Kingdom	71.19	60.55	46.81	11.28	14.90	8.26
Australia [2]	–	–	51.22	–	–	35.73
Other Countries	66.09	59.96	43.07	3.13	6.08	4.09
Natural Gas (Cdn$/mcf)						
Canada [2]	6.49	7.51	5.76	1.65	0.95	0.85
United States	7.86	10.56	7.89	1.58	1.22	1.02
United Kingdom	7.43	7.86	8.28	1.88	2.48	–

Notes:
1 *Sales prices and unit production costs are calculated using our working interest production after royalties.*
2 *Includes results of discontinued operations for 2005 and 2004. (See Note 14 to our Consolidated Financial Statements.)*

Proved Reserves including Proved Undeveloped Reserves

At December 31, 2006, we had 725 mmboe of proved oil and gas reserves before royalties (637 after royalties). This is a 55% increase over the prior year (62% after royalties). Including Syncrude, our total proved oil and gas and Syncrude reserves increased 34% to 1,049 mmboe (39% to 911 after royalties).

The following table provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding our Syncrude reserves. Refer to page 131 for proved reserves information on an after-royalties basis.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2005	117	145	90	105	11	468
Extension and Discoveries	11	25	7	4	30	77
Revisions	249	20	(11)	(8)	1	251
Production	(13)	(8)	(13)	(35)	(2)	(71)
December 31, 2006	**364**	**182**	**73**	**66**	**40**	**725**

Extensions and discoveries contributed 77 mmboe (67 after royalties). The majority of the increase results from new development projects at Usan, offshore West Africa, the Ettrick and Duart fields in the North Sea, Ringo in the Gulf of Mexico, and coalbed methane in Canada. Other increases relate to ongoing exploitation activities in the North Sea, Yemen, the Gulf of Mexico and Canada.

The revisions relate primarily to our Long Lake project. Under SEC rules, we are required to recognize bitumen reserves rather than the upgraded synthetic crude oil that we will produce and sell. As such, proved reserves recognition depends on year end oil prices, light/heavy differentials, diluent prices and natural gas prices. We initially recognized proved bitumen reserves at Long Lake in early 2004 when we sanctioned development of the project. The reserves were, however, written off at the end of the year due to wide light/heavy differentials and high natural gas costs. At the end of 2006, narrow light/heavy differentials and low natural gas costs allowed us to recognize proved bitumen reserves of 246 mmboe (219 after royalties). In the North Sea, the additions reflect increases at Buzzard as a result of development drilling and an increase in the proved recovery factor. In Canada, the additions relate primarily to our heavy oil properties where narrow light/heavy differentials increased the amount of economically recoverable reserves. Negative revisions occurred on Block 51 in Yemen and the Aspen field in the Gulf of Mexico as a result of lower than expected production performance.

Proved Undeveloped Reserves

The following table provides a summary of our proved undeveloped reserves (PUDs) for our oil and gas activities at December 31, 2006 and 2005:

	Before Royalties			After Royalties		
(mmboe)	PUDs	Total Proved [1]	% of Total	PUDs	Total Proved [1]	% of Total
Canada	216	364	59%	188	319	59%
United Kingdom	50	182	27%	50	182	27%
Yemen	9	66	14%	5	38	13%
United States	9	73	12%	7	63	11%
Other Countries	31	40	78%	25	35	71%
December 31, 2006	**315**	**725**	**43%**	**275**	**637**	**43%**
Canada	13	117	11%	11	101	11%
United Kingdom	128	145	88%	128	145	88%
Yemen	23	105	22%	13	59	22%
United States	15	90	17%	13	77	17%
Other Countries	1	11	5%	–	11	5%
December 31, 2005	**180**	**468**	**38%**	**165**	**393**	**42%**

Note:

1 *Excludes proved reserves for our Syncrude operations of 324 mmboe (274 after royalties) in 2006 and 318 mmboe (264 after royalties) in 2005.*

In 2006, our PUDs increased by 135 mmboe (110 after royalties). We added 206 mmboe (179 after royalties) at Long Lake relating to proved reserves outside of the initial 81 well-pair SAGD development area. We also added PUDs from our new development projects at Usan, Ettrick, Ringo, Duart and CBM. We converted 117 mmboe (112 after royalties) of PUDs to developed, with the majority relating to the completion of the Buzzard development project. Other small additions and conversions occurred from ongoing development activities at Canada, the United States, Yemen, the United Kingdom and Colombia.

In Canada, our PUDs increased from 13 mmboe (11 after royalties) to 216 mmboe (188 after royalties). Substantially all of the increase relates to Long Lake where we added 206 mmboe (179 after royalties). These PUDs are expected to be converted to developed over the next 20 years as we drill additional wells to provide feedstock to run the upgrader at capacity. The remaining PUDs relate to infill drilling, recompletions or facilities enhancements on our various heavy oil and natural gas fields. The majority of these PUDs are expected to be converted to producing reserves in 2007 and 2008. Also, a small portion of the PUDs relate to our CBM properties, which are expected to be converted to producing by infill drilling and field development planned for 2007 and 2008.

In the United Kingdom, our PUDs decreased from 128 mmboe (128 after royalties) to 50 mmboe (50 after royalties) primarily from completing the Buzzard development, which converted 80% of the related PUDs to developed. The remaining Buzzard PUDs are expected to be converted to proved over the next few years as we drill additional wells to keep the platform operating at capacity. PUDs were added by our Ettrick development, which we expect to convert to producing in 2008.

In Yemen, the PUDs are split relatively equally between our Masila and East Al Hajr Blocks. These reserves relate entirely to infill drilling, which we plan to carry-out during 2007 and 2008.

In the United States, our PUDS decreased from ongoing development of our Gulf of Mexico deep-water and shelf properties. In 2006, additions principally relate to the Ringo and Tobago developments, which are expected to be producing within the next two years.

In other countries, our PUDs increased by 30 mmboe (25 after royalties), resulting from recognizing proved reserves associated with our Usan development, offshore West Africa.

Excluding Long Lake and Usan, we expect to convert about 80% of our PUDs to producing in 2007 and 2008. Usan will be converted by 2011 when it is expected to come on stream. Long Lake PUDs will be converted over the next 20 years as initial SAGD wells deplete. At the same time, we expect our ongoing exploration and development activities to continue to add new PUDs.

SYNCRUDE MINING OPERATIONS

We hold a 7.23% participating interest in Syncrude Canada Ltd. (Syncrude). This joint venture was established in 1975 to mine shallow oil sands deposits using open-pit mining methods, extract the bitumen from the oil sands, and upgrade the bitumen to produce a high-quality, light (32° API), sweet, synthetic crude oil.

The Syncrude operation exploits a portion of the Athabasca oil sands deposit that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14 percent by weight and ore bearing sand thickness of 100 to 160 feet.

Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31, and 34) covering 258,000 hectares, 40 km north of Fort McMurray in northeast Alberta.

Syncrude mines oil sands at three mines: Base, North, and Aurora North. These locations are readily accessible by public road. Trucks and shovels are used to collect the oil sands in the open pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 270 million tons of oil sands per year and about 160 mmbbls of bitumen per year. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Base Mine uses hot water, steam, and caustic soda to create a slurry, while at the North Mine and the Aurora North Mine, the oil sands are mixed with warm water to produce a slurry.

The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading. The resulting products are then separated into naphtha, light gas oil, and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2006, about 40% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 60% was sold to refineries in Eastern Canada and the mid-western United States.

Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than 1.7 billion barrels of synthetic crude oil to Edmonton, Alberta, by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.

At December 31, 2006, our total investment in the property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities, was approximately $1.3 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be more than $2.5 billion.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating license for the eight oil sands leases through to 2035. The license permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start up of operations in 1978.

Syncrude pays a royalty to the Province of Alberta. Subsequent to 1987, this royalty was equal to 50% of Syncrude's deemed net profits after deduction of capital expenditures. In 1995, the Province of Alberta announced generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. In 1997, the Province of Alberta and the Syncrude owners agreed to move to the generic royalty terms when the total of all allowed capital costs incurred after December 31, 1995 equalled $2.8 billion (gross). That total was surpassed at the end of 2001. In 2006, we realized full recovery of allowed capital costs and, as a result, Syncrude royalties are assessed at 25% of net revenues.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 25 miles north of the main Syncrude site. The next expansion of Syncrude came on-stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project. Our share of capital spending in 2007 is expected to be $50 million.

In 2006, Syncrude's production of marketable synthetic crude oil was 258,400 bbls/d. Nexen's share was 18,700 bbls/d before royalties (16,900 after royalties).

The following table provides some operating statistics for Syncrude operations:

	2006	2005	2004
Total Mined Volume [1]			
Millions of Tons	428	353	389
Mined Volume to Oil Sands Ratio [1]	2.2	2.1	2.1
Oil Sands Processed			
Millions of Tons	192	169	188
Average Bitumen Grade (weight %)	11.3	11.1	11.1
Bitumen in Mined Oil Sands			
Millions of Tons	22	19	21
Average Extraction Recovery (%)	90	89	87
Bitumen Production [2]			
Millions of Barrels	112	94	103
Average Upgrading Yield (%)	85	85	86
Gross Synthetic Crude Oil Shipped [3]			
Millions of Barrels	94	78	87
Nexen's Share of Marketable Crude Oil			
Millions of Barrels Before Royalties	6.8	5.7	6.3
Millions of Barrels After Royalties	6.2	5.6	6.1

Notes:

1 *Includes pre-stripping of mine areas.*

2 *Bitumen production in barrels is equal to bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.*

3 *Approximately 1.2% of the produced synthetic crude oil is used internally, primarily for diesel that fuels the trucks and shovels at Syncrude. The remaining synthetic crude oil is sold externally.*

ENERGY MARKETING

Our marketing group sells proprietary and third-party natural gas, crude oil, natural gas liquids, ethanol and power in certain regional global markets. We have built a solid strategic presence within various North American regional markets and extended our presence into certain global markets as well. We focus on securing access to transportation, storage and facilities, as well as commodities we produce or acquire. We optimize the margin on our base business by physically and financially trading around our access to these physical assets. We also trade financially for profit where we see opportunities in the market. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our oil and gas production;
- provide market intelligence in support of our oil and gas operations;
- provide superior customer service to producers and consumers;
- capitalize on market opportunities through physical and financial trading; and
- optimize physical assets or contracts to which we have access.

This strategy aligns with our corporate focus on extracting full value from our assets and provides us with the market intelligence needed to deliver current and future oil and gas production to market at competitive pricing.

North American Gas Marketing

The marketing and trading of North American natural gas is our marketing group's largest revenue source. We focus on key regional markets where we have a strategic presence—solid customer relationships, in-depth understanding of the market or established physical assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further revenue by:

- capitalizing on location spreads (differences in prices between locations) using our transportation assets;
- capitalizing on time spreads (differences in prices between summer and winter) using our storage assets; and
- financial trading of location and time spreads.

We have offices in key regions including Calgary, Detroit and Houston. Our Calgary office provides a variety of services, including supply, storage, and transportation management as well as netback pool arrangements and other customer services. Our customers include producers and consumers in western Canada as well as consumers (including utilities) in eastern Canada, the north-eastern United States and the US mid-continent. Our Detroit office works closely with Calgary to provide services to our customers. Our presence in Houston has established us in the Gulf Coast region where we have our own production.

We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

In 2003 and 2004, we grew our asset base by acquiring physical gas purchase and sales contracts, as well as natural

Marketing Office Locations

gas transportation capacity, on favourable terms. This gives us access to new third party gas supply until 2008, pipeline capacity to 2016 and new relationships that have enabled us to negotiate new gas purchase and sales contracts. In 2006, we continued to grow our storage and transportation positions through acquisitions as well as bidding processes. Our position as a physical marketer at multiple delivery points in key markets gives us the flexibility to capitalize on time and location spreads. With pipeline capacity, we can move gas from producing regions to take advantage of price differences. At the end of 2006, we held 3.3 bcf/d of pipeline capacity, primarily between western Canada and the eastern US, and we continue to expand our presence into other markets within North America. We also use storage capacity to store typically cheaper summer gas in the ground until the winter heating season arrives. We had access to 50 bcf of natural gas storage facilities at the end of the year.

We use our access to transportation and storage facilities to optimize returns, capitalizing on location and time spreads.

In addition to transportation and storage assets, we hold financial contracts that enable us to capture profits around time and location spreads. The risks we assume on these contracts are based on fundamental analysis and knowledge of regional markets. The risk is managed proactively by our product group teams and monitored by our risk group, with regular reporting to management and the board of directors.

International Crude Oil Marketing

Our crude oil business focuses on marketing physical crude oil to end-use refiners. The crude oil group markets our own production and more than 500,000 bbls/d of third-party field production to refiners from producing regions where we operate. In addition to physical marketing, we take advantage of quality differentials and time spreads.

Our North American operations focus on key regions supported by our offices in Calgary, Houston and Denver. In western Canada, our producer services group concentrates on the procurement of a diversified supply base, while our trading team seeks to optimize the mix for sale to refiners. Traditionally, the Chicago and Denver areas have been key markets for our western Canadian crude, however, we continue to expand our presence into the US Gulf Coast. Our deep-water Gulf of Mexico crude oil production has given us the opportunity to expand our presence in that market through our Houston office. At the end of 2006, we had access to 1.7 mmbbls of storage and over the course of the year, moved approximately 705 mbbls per day.

In the last two years, we acquired two North American natural gas liquid (NGL) and ethanol businesses that focus on buying and selling NGLs as well as diesel, ethanol and natural gasoline. These businesses acquire and move NGLs into the US midwest and Gulf Coast from Canada, as well as providing denaturant for ethanol production and the marketing of finished ethanol in the US. At the end of 2006, we had access to 550 mbbls of storage and over the course of the year, moved approximately 25 mbbls per day of product.

Internationally, we focus on the physical marketing of our Yemen crude oil. In order to meet customer needs, we may occasionally market other regional crude types. In addition to our own crude, we market production for our partners and third parties in the Yemen region. By locating our international crude oil marketing office in Singapore, we are well positioned to serve both the producing region and the Asian refining market. We established an office in London, United Kingdom to maximize the value of our North Sea production. With Buzzard crude on stream in early 2007, we expect to increase our presence in various global markets, ensuring we maximize the value of this production.

Our crude oil marketing group also holds financial contracts intended to capture trading profits around time, quality and location spreads. Like gas marketing, the risks assumed are based on fundamental analysis and proprietary knowledge of regional markets, and are monitored by our risk group.

North American Power Marketing

Our power marketing group is responsible for optimizing the use of our 50% interest in a 100 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, as well as our recently completed 70 MW Soderglen wind power operation in southern Alberta. We also market power to larger commercial, industrial and municipal clients in Alberta. With the 2005 acquisition of a commercial/industrial marketing business in Alberta, we became the largest supplier of power to the commercial and industrial sectors in the province. Our Balzac facility began operations in 2001 and Soderglen in October 2006. We expect to increase our power generation capacity with a 170 MW co-generation facility at Long Lake in 2007. We have a 50% interest in this project.

European Gas and Power Marketing

In 2006, we acquired a UK-based European gas and power marketing business that focuses on UK gas and power as well as German power. In 2007, we expect to increase our presence in both the UK and continental Europe gas and power markets.

CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. We have retained a 61.4% interest in our chemicals business, and we continue to fully consolidate chemicals in our Consolidated Financial Statements.

Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing facilities are modern, reliable and strategically located to capitalize on competitive power costs or transportation infrastructure to minimize production and delivery costs. This enables us to have reliable supplies and low costs—key factors for marketing bleaching chemicals.

Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products, making up over half our cash costs. Therefore, our current facilities are strategically located to take advantage of economic power sources. Our second highest cost is transportation. The proximity of our manufacturing plants to major customers and competitive freight rates minimize our transportation costs. Labour is also a significant manufacturing cost. Approximately 50% of our workforce is unionized with collective agreements in place at all of our unionized plants.

To grow value in our chemicals business, we focus on reducing our costs while maintaining market share, building a sustainable North American customer base and capturing new offshore opportunities.

Average Annual Production Capacity

(short tons)	2006	2005	2004
Sodium Chlorate			
North America	446,208	446,208	446,617
Brazil	68,563	68,563	68,563
Total	**514,771**	**514,771**	**515,180**
Chlor-alkali			
North America	356,002	356,002	356,002
Brazil	109,430	109,430	109,430
Total	**465,432**	**465,432**	**465,432**

North America

The North American pulp and paper industry consumes approximately 95% of the continent's sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume adjustment provisions. Approximately 32% of this production is sold in Canada, 61% in the US, and the rest is marketed offshore.

We are the third-largest manufacturer of sodium chlorate in North America with four Canadian facilities: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; and Beauharnois, Quebec.

In October 2004, we completed an expansion of our plant in Brandon, Manitoba increasing capacity to 260,000 tonnes per year. This expansion replaced higher-cost capacity idled in 2002 at Taft, Louisiana. Brandon is the world's largest sodium chlorate facility and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America. In late 2006, we began another expansion of our plant in Brandon which is expected to increase capacity by 32,300 tonnes per year, early in 2008.

Our chlor-alkali facility at North Vancouver, British Columbia, manufactures caustic soda, chlorine and muriatic acid. Almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States.

Brazil

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Cellulose S.A. (Aracruz), the leading manufacturer of pulp in Brazil. The majority of the sodium chlorate production is sold to Aracruz under a long-term sales agreement that expires in 2024. This agreement had an initial six-year take-or-pay component that ended in 2005. Most of the chlorine and about 20% of the sodium chlorate production is sold in the merchant market under shorter-term contractual arrangements. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. The majority of our electricity needs are supplied by a long-term supply contract in Brazil.

GOVERNMENT REGULATIONS

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We participate in many industry and professional associations and monitor the progress of proposed legislation and regulatory amendments.

ENVIRONMENTAL REGULATIONS

Our oil and gas, Syncrude and chemical operations are subject to government laws and regulations designed to protect and regulate the discharge of materials into the environment in countries where we operate. We believe our operations comply in all material respects with applicable environmental laws. To reduce our exposure, we apply industry standards, codes and best practices to meet or exceed these laws and regulations. Occasionally, we may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

We have an active safety, environment and social responsibility group that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner. We have developed policies for continuing compliance with environmental laws and regulations in the countries in which we operate.

Environmental Provisions and Expenditures

The ultimate financial impact of environmental laws and regulations is not clearly known and cannot be reasonably estimated as new standards continue to evolve in the countries in which we operate. We estimate our future environmental costs based on past experience and current regulations. At December 31, 2006, $704 million ($1,770 million, undiscounted) has been provided in our Consolidated Financial Statements for asset retirement obligations. In 2006, we increased our retirement obligations for future dismantlement and site restoration by $75 million primarily from the development of the Buzzard field in the North Sea.

In 2006, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $44 million. Our operating expenditures for environmental-related matters were approximately $6 million. In 2007, we estimate these expenditures to be approximately $21 million.

EMPLOYEES

We had 3,687 employees on December 31, 2006, of which 266 were employed under collective bargaining schemes. Information on our executive officers is presented in Item 10 of this report.

ITEM 1A. RISK FACTORS

RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in our industry and some of which are unique to our operations.

Competitive forces may limit our access to natural resources, and create labour and equipment shortages.

The oil and gas industry is highly competitive, particularly in the following areas:

- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include national oil companies, major integrated oil and gas companies and various other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. The pulp and paper chemicals market is also highly competitive. Key success factors in each of these markets are price, product quality, and logistics and reliability of supply.

Competitive forces may result in shortages of prospects to drill, shortages of labour and equipment to carry out exploration, development or operating activities, and shortages of infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could have a negative impact on costs and prices and, therefore, our financial results.

Exploration, development and production risks and natural disasters could result in liability exposure or loss of production or reserves.

Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

We operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. At Balzac, just north of Calgary, we operate a gas plant that has been producing sour gas for over 40 years. In North Vancouver, we operate, indirectly through ownership in Canexus Limited Partnership a chlor-alkali plant that has been producing chlorine for almost 50 years.

We may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may have a material impact on our financial results.

Our offshore operations are subject to unique operating risks.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production.

Our operations in the Gulf of Mexico have been suspended, from time to time, due to hurricanes or tropical storms. In the last five years, we have had a few instances where production was suspended for an extended period of time and damage to facilities was incurred. In late August 2005, we shut-in all of our production in the Gulf of Mexico, consisting of approximately 50,000 boe/d before royalties, and ceased drilling operations in anticipation of Hurricane Katrina. Production was restored in early September for most of our fields. In late September 2005, we again shut-in all of our production and ceased drilling operations in anticipation of Hurricane Rita. While we incurred minimal damage to most of our facilities, extensive damage was incurred to the third party infrastructure necessary to accommodate our production. As a result, our 2005 annualized production was reduced by approximately 6,000 boe/d. These storms also resulted in damage to rigs under contract with us, which increased our costs and delayed our drilling schedule. In 2002, our facilities at Eugene Island 295 were damaged during Hurricane Lili. Production from this field was suspended for about four months while temporary production facilities were put in place. During this period, production volumes were reduced by approximately 2,500 boe/d. Production was restored at a reduced rate through temporary facilities for approximately six months while installation of new permanent facilities was completed. It is estimated that volumes were reduced by approximately 1,800 boe/d during this period. In each of these instances, there was no significant financial impact after business interruption and property insurance claims.

Our exploration and development capital programs in our offshore operations are exposed to risk of delay or additional

costs by limited access to drilling rigs. Recent industry pressure in the Gulf of Mexico following storm damage sustained in the 2005 hurricane season has reduced the availability of drilling rigs. Our profitability and success at finding reserves may be reduced by extended delays and/or higher costs of obtaining drilling rigs.

Without reserve additions, our reserves and production will decline over time and we require capital to produce remaining reserves.

Our future crude oil and natural gas reserves and production, and therefore our operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, development or acquisitions, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves will be impaired.

Over the past three years, we experienced net negative revisions of 19 million boe to our proved reserves (before royalties). This includes net negative revisions of 25 million boe, representing about 2% of worldwide proved reserves (including Syncrude), related to technical revisions primarily on our producing properties, partially offset by 6 million boe of net positive economic revisions related to changes in year-end prices and costs. In Yemen, negative revisions of 27 million boe occurred largely in 2004 and resulted primarily from lower-than-expected production performance, drilling results and updated geological mapping. In the United States, negative revisions of 29 million boe occurred largely in 2005 and 2006 and resulted primarily from lower-than-expected production performance at our deep-water Aspen property and at various properties on the shelf. These negative revisions were somewhat offset by positive revisions of 37 million boe in our Buzzard field due to updated geological mapping.

Under SEC rules, we must recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce from Long Lake. As a result, we expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen and heavy oil reserves are sensitive to year-end prices. In particular, since we recognize our oil sands as bitumen reserves and they are related to one project, all or none of the reserves will likely be considered economic depending on the year-end prices for bitumen, diluent and natural gas, even though the Long Lake integrated project has virtually no exposure to these factors.

Our proved reserves include undeveloped properties that require additional capital to bring them on-stream.

Under SEC rules, the definition of proved undeveloped reserves includes reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells may begin production. Such reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

During the past three years, our total proved undeveloped reserves before royalties have increased from 124 mmboe to 315 mmboe (87 mmboe to 275 mmboe after royalties). As a result, our proved undeveloped reserves have increased from 23% to 43% of our proved reserves excluding Syncrude (22% to 43% after royalties). Proved undeveloped reserves increased primarily at our Long Lake oil sands project and various other worldwide development projects, partially offset by the completion of the Buzzard development and ongoing development activities elsewhere.

Our heavy oil production is more expensive and yields lower prices than light oil and gas.

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil making it more susceptible to supply and demand fundamentals which may cause the price to decline.

Any one or combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

Our Long Lake project faces additional risks compared to conventional oil and gas production.

Our Long Lake project is planned as a fully integrated production, upgrading and co-generation facility. We intend to use Steam Assisted Gravity Drainage (SAGD) technology to recover bitumen from oil sands. As designed, the bitumen will be partially upgraded using the proprietary OrCrude™ process, followed by conventional hydrocracking to produce a sweet, premium synthetic crude oil. The OrCrude™ process also yields liquid asphaltines that will be gasified into a syngas. This syngas will be used as a fuel source for the SAGD process, a source of hydrogen for use in the upgrading process, and to generate electricity through a co-generation facility.

We have a 50% working interest in this project, and our share of the capital costs is estimated to be $2.3 billion ($4.6 billion gross). Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

In addition to the risks associated with heavy oil production stated above, risks associated with our Long Lake oil sands project include the following:

Uncertain Timeline and Cost of the Project

The Long Lake project is currently in the construction stage. There is a risk that actual costs to construct and develop may be higher than expected or that the project may not be completed on time or at all due to many factors, including:

- construction performance falling below expected levels of output or efficiency;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- inability to attract sufficient numbers of qualified workers;
- design errors;
- contractor or operator errors;
- non-performance by third-party contractors;
- changes in project scope;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- breakdown or failure of equipment or processes;
- violation of permit requirements;
- catastrophic events such as fires, earthquakes, storms or explosions; and
- disruption in the supply of energy.

The capital cost estimate at the time of our board's sanctioning the project in February 2004 was $3.4 billion (gross). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to increase certainty and reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million (gross). In early 2006, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million (gross). These scope changes increased the estimated project cost to $3.8 billion. High activity in the oil sands region is placing ongoing pressure on the costs of labour and services. In addition, labour productivity has been lower than anticipated, requiring a larger workforce to maintain progress. After a review of all trends, the projected cost of Long Lake has been increased to $4.6 billion (gross).

Application of Relatively New SAGD Bitumen Recovery Process

SAGD has been used in western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade. However, application of SAGD to the in-situ recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, however several commercial SAGD projects have been in steady state operation for over five years.

Our estimates for performance and recoverable volumes for the Long Lake project are based primarily on our three well-pair SAGD pilot and industry performance from SAGD operations in like reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our assumptions included average well-pair productivity of 900 bbls/d of bitumen and a long-term steam-to-oil ratio of 3.0. There can be no assurance that our SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, purchase natural gas for additional steam generation, and/or make short-term bitumen purchases. These could have a significant adverse impact on the future activities and economic return of the Long Lake project.

Application of New Bitumen Upgrading Process

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude will be the first commercial application of the process although we have operated

it in a 500 bbl/d demonstration plant. There can be no assurance that the commercial upgrader being constructed at Long Lake will achieve the same or similar results as the demonstration plant or the results which are forecast. If we are unable to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading it, which would expose us to the following risks:

- the market for bitumen is limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent which may cause its price to increase;
- the market price for bitumen is relatively low reflecting its quality differential;
- the market price for bitumen fluctuates over the course of the year; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from those we have assumed. This would cause a material decrease in expected earnings from the project and the project may not be profitable under these conditions.

Dependence on OPTI Canada Inc.

We are undertaking the Long Lake project jointly with OPTI Canada Inc. (OPTI) pursuant to a joint venture agreement governing the construction, ownership and joint operation of the project. The agreement provides for the creation of a management committee that is responsible for the supervision and direction of the management and operation of the project, the supervision and control of the operators and all other matters relating to the development of the project. If our interest in any element of the project falls below 25%, OPTI may be able to make decisions respecting that element without our input, which may adversely affect our operations.

Dependence upon Proprietary Technology

The success of the project and our investment depends to a significant extent on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licensed by OPTI. OPTI currently relies on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licenses and patents, to secure the rights to utilize its proprietary technology and the proprietary technology of third parties. OPTI may have to engage in litigation in order to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of the patents or proprietary rights of third parties. This kind of litigation can be time-consuming and expensive, regardless of whether or not OPTI is successful. The process of seeking patent protection can itself be long and expensive, and there can be no assurance that any currently pending or future patent applications of OPTI or such third parties will actually result in issued patents, or that, even if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Furthermore, others may develop technologies that are similar or superior to the technology of OPTI or such third parties or design around the patents owned by OPTI and/or such third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for the additional technologies required for the possible further expansion of the Long Lake upgrader.

Operational Hazards

The operation of the project will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that our insurance will be sufficient to cover any such casualty occurrences or disruptions. The project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. The project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and devel-

opment and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

The Long Lake SAGD operation and upgrader will process large volumes of hydrocarbons at high pressure and temperatures and will handle large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake project will produce sour gas, which is gas containing hydrogen sulphide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. The project will include integrated facilities for handling and treating the sour gas, including the use of gas sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shut down of operations.

The Long Lake project will produce carbon dioxide emissions. Carbon dioxide is a greenhouse gas that will be regulated by the Kyoto Protocol, which may come into effect in Canada. Risk factors relating to environmental regulation are provided separately herein.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the project and on us.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of petroleum interests and the distribution and marketing of petroleum products. The Long Lake project competes with other producers of synthetic crude oil blends and other producers of conventional crude oil. Some of the conventional producers have lower operating costs than the project is anticipated to have. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies, other than OPTI and us, have announced plans to enter the oil sands business and begin production of synthetic crude oil, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Some of our production is concentrated in a few producing assets.

A significant portion of our production is generated from highly productive individual wells or central production facilities. Examples include:

- central processing facilities, oil pipelines, and export terminal at our two Yemen operations;
- Gunnison SPAR production platform in the Gulf of Mexico;
- highly productive Aspen wells tied-in to a third-party processing facility in the Gulf of Mexico;
- upgrading facilities at Syncrude in the Athabasca oil sands; and
- Scott and Buzzard production platforms in the North Sea.

As significant production is generated from each of these assets, any single event causing an interruption to any one of these operations could result in the loss of production.

We may not achieve commercial production rates in our coalbed methane operations.

Coalbed methane (CBM) is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal. If the coal is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area. Regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

The Mannville coals in the Fort Assiniboine region of Alberta are generally deeper than other commercial CBM projects in the Horseshoe Canyon and are water saturated. A significant period of time may be required to sufficiently dewater the coals to determine if commercial production is feasible. As a result, we may have to invest significant capital in CBM assets before they achieve commercial rates of production. The wells may never achieve commercial rates of production as there are no other commercially proven Mannville CBM projects in operation.

CBM projects in some areas of the United States have had negative public reaction due to certain water disposal practices. In Canada, as in the United States, water disposal practices are regulated to ensure public safety and water conservation. Nevertheless, negative public perception around CBM production could impede our access to the resource.

We have significant upfront commitments related to our current development projects.

We have significant commitments in connection with various development activities currently underway. At Long Lake, we essentially completed module and site construction of the SAGD facilities in 2006 and steam injection is expected to commence at the end of first quarter of 2007. With respect to the Long Lake upgrader, module fabrication is largely complete and over 95% of the modules are on site. Construction of the upgrader is approximately 80% complete and start up is scheduled for late 2007. At Long Lake, we are exposed to the possibility of cost overruns and/or delays in the commencement of commercial production, which may be significant. Specific risk factors relating to our Long Lake oil sands project are provided separately.

We operate in countries with political and economic risk.

We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists which may have material adverse financial consequences. For instance, on September 15, 2006 our oil export terminal in Yemen was assaulted by two explosive laden vehicles. One worker was killed and two others received minor injuries. The ability of the terminal to receive and export oil was not affected and operations are continuing as normal. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

We may be affected by changes in government rules and regulations.

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. For example, the US government has proposed increases to the royalty rates for new deep-water Gulf of Mexico leases and has proposed amendments to deep-water leases issued in 1998 and 1999. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. Changes in government regulations could have an adverse effect on our results of operations and financial condition.

Our operations are exposed to environmental liabilities.

Environmental liabilities inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the disposal or release of specified substances. This could have an adverse financial consequence.

Certain operations require the use of fresh and saline water. We currently use sub-surface sources of water for these operations. Additional costs may be incurred if allocation limits are placed on our saline water usage, if our sub-surface fresh water needs exceed allocated amounts or if existing sub-surface fresh water allocations are reduced.

Our operations could be subject to changes in regulations related to climate change.

The Kyoto Protocol came into force on February 16, 2005. Canada ratified the Kyoto Protocol in December 2002. In 1997, Canada committed to an emission reduction of 6% below 1990 levels during the First Commitment period (2008 to 2012). Since that time, the Canadian federal government and various provincial governments have grappled with the issue of climate change and a number of proposals have come and gone. Bill C-30 (Canada's Clean Air Act) has been sent to

a special parliamentary committee that intends to report back to parliament by the end of March 2007. This Bill contains proposals to deal with criteria air contaminants (CACs) and greenhouse gases (GHGs) and outlines proposed changes to the Canadian Environmental Protection Act 1999, the Energy Efficiency Act and the Motor Vehicle Fuel Conservation Standards Act. The proposals seek to apply intensity-based targets for GHGs and absolute caps on CACs in the period up to 2020–2025, ultimately leading to absolute caps on GHGs. It is unclear if and when Bill C-30 will become law.

Any required reductions in the GHGs emitted for our operations could result in increases in our capital or operating expense, or reduced operating rates, especially those related to the Long Lake project, which could have an adverse effect on our results of operations and financial condition.

Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our trading operations expose us to the risk of financial losses from various sources. The markets in which we trade are susceptible to significant changes, which could expose us to the risk of material financial losses. Significant changes in the commodities and financial markets could require us to provide additional liquidity to support our marketing operations. Adverse credit related events such as a downgrade of our credit rating to non-investment grade could require additional collateral to be placed with counter-parties. Any significant loss of liquidity may result in delays and/or cancellation of our development plans.

Use of marine transportation may expose us to the risk of financial loss and reputational damage.

From time to time, we may choose to charter marine vessels for the transportation of crude oil. This may expose us to the risk of financial loss and reputational damage in the event of oil spills.

ITEM 1B. UNRESOLVED STAFF COMMENTS

There are no unresolved staff comments with the SEC that have been outstanding for more than 180 days before December 31, 2006.

ITEM 3. LEGAL PROCEEDINGS

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect on our consolidated financial position or results of operations. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US Environmental Protection Agency (EPA), state environmental agencies, and certain third parties with respect to certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands, and lawsuits have been received for certain sites related to historical operations and activities in the US for which, although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

In June 2003, a subsidiary of Occidental Petroleum Corporation (Occidental) initiated an arbitration against us at the International Court of Arbitration in the International Chamber of Commerce (ICC Court) regarding an Area of Mutual Interest agreement relating to certain portions of Block 51 in the Republic of Yemen. In April 2006, the ICC Court concluded that we breached this agreement and as a result, Occidental was entitled to monetary damages. In late 2006, we agreed to settle the arbitration with Occidental for US$135 million. This amount was accrued and included in other expenses in our Consolidated Statement of Income during 2006. No further amounts are expected to be payable under the settlement.

On September 5, 2005, there was a gas release on the Scott Platform in the North Sea. No-one was harmed as a result of the incident, but Nexen was fined £400,000 under the UK Health and Safety at Work Act, 1974 and the Offshore Installation (Prevention of Fire and Explosion, and Emergency Response) Regulations, 1995.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2006.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY.

On December 31, 2006, there were 1,454 registered holders of common shares and 262,513,206 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings. During the year, we made no purchases of our own equity securities.

Trading Range of Nexen's Common Shares

	TSX (Cdn$)		NYSE (US$)	
($/share)	High	Low	High	Low
2006				
First Quarter	68.10	54.34	59.94	46.98
Second Quarter	69.50	50.82	61.68	45.63
Third Quarter	71.22	52.13	63.65	46.70
Fourth Quarter	65.79	52.91	58.37	46.90
2005				
First Quarter	35.50	23.55	29.18	19.44
Second Quarter	39.85	29.53	32.32	23.28
Third Quarter	60.67	40.25	51.73	31.95
Fourth Quarter	59.54	43.77	51.69	36.80

Quarterly Dividends Declared on Common Shares

($/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2006	0.05	0.05	0.05	0.05
2005	0.05	0.05	0.05	0.05

Payment date for dividends was the first day of the next quarter. All dividends paid to holders of common shares in 2006 have been designated as "eligible dividends" for Canadian tax purposes.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian", as defined, file notice with Investment Canada and obtain government approval prior to acquiring control of a Canadian business, as defined. Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities.

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. According to the Plan, a right is attached to each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares, and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our board can defer the separation date.

Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2008 to remain effective past that date. A copy of the Plan is available on our website at www.nexeninc.com.

ITEM 6. SELECTED FINANCIAL DATA

Five-Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn$ millions, except per share amounts)	2006	2005	2004	2003	2002
Oil & Gas and Syncrude Production					
Production Before Royalties (mboe/d) [2]	212	242	250	269	269
Production After Royalties (mboe/d) [2]	156	173	174	185	176
Results of Operations					
Revenue					
Oil & Gas and Syncrude [1]	3,656	3,535	2,573	2,261	1,966
Marketing	1,373	864	625	586	496
Chemicals	413	413	383	377	369
Other	(47)	(193)	59	31	8
Total Revenue	5,395	4,619	3,640	3,255	2,839
Net Income from Continuing Operations	579	658	705	419	270
Basic Earnings per Common Share from Continuing Operations ($/share)	2.21	2.52	2.74	1.69	1.10
Diluted Earnings per Common Share from Continuing Operations ($/share)	2.15	2.47	2.71	1.68	1.09
Net Income	579	1,110	788	420	352
Basic Earnings per Common Share ($/share)	2.21	4.26	3.06	1.70	1.44
Diluted Earnings per Common Share ($/share)	2.15	4.17	3.03	1.68	1.42
Financial Position					
Total Assets [2]	17,079	14,493	12,339	7,703	6,764
Long-Term Debt [3]	4,618	3,630	4,214	2,470	2,575
Shareholders' Equity	4,614	3,961	2,892	2,131	1,812
Capital Investment, including Acquisitions	3,408	2,638	4,264	1,432	1,545
Dividends per Common Share ($/share) [4]	0.20	0.20	0.20	0.163	0.15
Common Shares Outstanding (thousands)	262,513	261,141	258,399	251,212	245,932

Notes:

1 *During 2003, we sold non-core conventional light oil assets in southeast Saskatchewan in Canada producing 9,000 bbls/d. In late 2004, we concluded production from our Buffalo field, offshore Australia, as anticipated. In the third quarter of 2005, we sold Canadian conventional oil and gas properties in Saskatchewan, British Columbia and Alberta producing 18,300 bbls/d. The results of these operations have been shown as discontinued operations.*

2 *In 2003, production increased from our deep-water Aspen development in the Gulf of Mexico in the United States. In 2004, production declined from our maturing assets in Yemen at Masila, in Canada and in the United States on the Gulf of Mexico Shelf. In late 2004, we acquired North Sea assets and began production from Block 51 in Yemen. In 2005, we sold producing properties in Canada and suffered hurricane-related downtime in the Gulf of Mexico. A full year's production from the North Sea and Block 51 in Yemen offset declines caused by these events. In 2006, declines in Yemen at Masila reduced production volumes.*

3 *In December 2004, we drew US$1.5 billion on unsecured acquisition credit facilities to finance the purchase of North Sea assets. The remainder of the purchase price was funded from cash on hand. The acquisition credit facility was repaid in 2005 with proceeds from the issuance of US $1.04 billion in senior notes in the first quarter and from our asset disposition program in the third quarter. Our long-term debt increased in 2006 as a result of our investment in capital projects, primarily at Buzzard and Long Lake.*

4 *Quarterly dividends were increased to 5¢ per share in the fourth quarter of 2003.*

MD&A

Our 2006 accomplishments position us for an exciting 2007 as we plan to ramp up production at Buzzard, bring Long Lake on stream, evaluate our recent discoveries and continue exploring.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 21 to the Consolidated Financial Statements. The date of this discussion is February 9, 2007.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities include our Syncrude activities since the product produced from Syncrude competes in the oil and gas market. Oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

Note: Canadian investors should read the Special Note to Canadian Investors on page 81 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

EXECUTIVE SUMMARY

(Cdn$ millions)	2006	2005	2004
Net Income	601	1,140	793
Earnings per Common Share, Basic ($/share)	2.29	4.38	3.08
Cash Flow from Operating Activities	2,374	2,143	1,606
Production before Royalties (mboe/d) [1]	212	242	250
Production after Royalties (mboe/d)	156	173	174
Capital Investment, including Acquisitions	3,408	2,638	4,264
Net Debt [2]	4,730	3,639	4,285
Average Foreign Exchange Rate (Canadian to US dollar)	0.88	0.83	0.77
Proved Oil and Gas Reserves before Royalties (mmboe) [3]	725	468	542
Proved Oil and Gas Reserves after Royalties (mmboe) [3]	637	393	451
Proved Syncrude Reserves before Royalties (mmboe) [3]	324	318	301
Proved Syncrude Reserves after Royalties (mmboe) [3]	274	264	255

Notes:

1 *Production before royalties reflects our working interest before royalties and includes production of synthetic crude oil from Syncrude. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.*

2 *Long-term debt and short-term borrowings less cash and cash equivalents.*

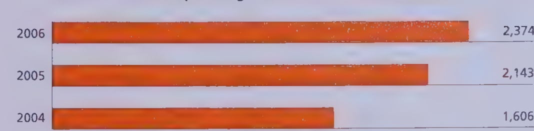
3 *Includes developed and undeveloped proved reserves as at December 31.*

Strong commodity prices and record results from our energy marketing group contributed to net income and cash flow from operating activities. WTI reached new trading highs during the year and our realized oil and gas price was $62.92/boe, 9% above 2005. The marketing group contributed record results, generating value from the optimization of storage and transportation capacity, as well as financially trading price differences caused by location, product quality and time. At the beginning of the year, the UK government increased the supplementary tax on oil and gas activities in the North Sea. As a result, we recorded $277 million of future income tax expense. Our 2006 income also included $151 million of expense in connection with our Block 51 arbitration. Last year, our net income included gains of $225 million from the sale of Canadian oil and gas properties and a gain of $193 million on the sale of a portion of our interest in our chemicals business.

Our combined oil & gas and Syncrude production was lower than 2005 levels as we continue to transition from maturing production in Yemen and Canada to new higher-return production in 2007, primarily in the North Sea and the Gulf of Mexico. The 2005 sale of Canadian conventional oil and gas assets reduced our 2006 volumes by 10,700 boe/d before royalties (8,100 boe/d after royalties) as compared to last year. As expected, our Masila assets continued to mature and production declined 16,800 boe/d (7,600 boe/d after royalties). Our ongoing investment in Masila is to maximize the recovery of the remaining reserves before our licence expires in 2011. With Buzzard on stream in early January 2007, our 2007 net production is expected to grow 50% to average between 230,000 boe/d and 260,000 boe/d, after royalties, and between 275,000 boe/d and 305,000 boe/d, before royalties.

In 2006, our largest annual capital program was focused on our major development projects at Buzzard and at Long Lake. Development of Buzzard in the North Sea was completed during the year and the field began producing on January 7, 2007. Peak production rates of 85,000 boe/d, net to us, are expected by mid 2007. At Long Lake, we invested over $1 billion on the SAGD component of the project and on construction of the upgrader. We expect steam injection to begin at the end of the first quarter of 2007, with upgrader start up scheduled for late 2007. At its peak, we expect our share of synthetic crude oil from phase 1 of Long Lake to be 30,000 bbls/d. At Syncrude, the Stage 3 expansion was brought on stream in 2006, adding 8,000 bbls/d of production capacity. Late in the year, we completed an additional development well at Aspen in the Gulf of Mexico, and we expect 2007 Aspen production to average between 15,000 and 20,000 boe/d.

Cash Flow from Operating Activities (Cdn$ millions)



Our 2006 exploration program was focused on drilling 20 wells, primarily in the Gulf of Mexico and the North Sea. We had successful results from Alaminos Canyon Block 856 (Great White West) and Ringo in the Gulf of Mexico, and Golden Eagle in the North Sea.

Our net debt increased from 2005 as a result of our investment in capital projects, primarily at Buzzard and Long Lake. We drew upon our committed term credit facilities during the year as our capital spending exceeded our cash flow by approximately $1 billion.

Throughout 2006, the Canadian dollar continued to strengthen relative to the US dollar. Our sales revenue is denominated in or referenced to US dollars. As a result, our revenues decline as the US dollar weakens. On the other hand, our US-dollar capital spending and operating costs are lower when translated to Canadian dollars. Overall, the weaker US dollar reduced our 2006 cash flow from operating activities and net income by $223 million and $98 million, respectively.

During 2006, our proved oil and gas and Syncrude reserves additions replaced more than 400% of our oil and gas and Syncrude production (500% after royalties) as shown in the following table:

(mmboe)	Before Royalties	After Royalties
Production		
Oil and Gas	71	51
Syncrude	7	6
Total	**78**	**57**
Extensions, Discoveries and Revisions		
Oil and Gas	328	295
Syncrude	13	16
Total	**341**	**311**

The majority of our 2006 additions came from our development projects at Long Lake in the Athabasca oil sands, Ettrick in the North Sea and Usan, offshore West Africa. We included 246 mmboe of bitumen (219 after royalties) at Long Lake as a result of strong year-end bitumen prices and lower natural gas costs. The Ettrick development was sanctioned during the year, contributing 18 mmboe of proved reserves (18 after royalties). At Usan, offshore West Africa, we added 30 mmboe of proved reserves (25 after royalties). Reserves were also added from ongoing activities in Canada, the Gulf of Mexico and the North Sea.

CAPITAL INVESTMENT

(Cdn$ millions)	Estimated 2007	2006	2005
Major Development	1,000	1,849	1,550
Early Stage Development	400	123	54
New Growth Exploration	700	491	456
Core Asset Development	700	748	524
Total Oil & Gas and Syncrude	2,800	3,211	2,584
Marketing, Corporate, Chemicals and Other	100	197	54
Total Capital	**2,900**	**3,408**	**2,638**

Our strategy and capital programs are focused on growing long-term value for our shareholders. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow; and
- exploration projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning our operations toward less mature basins and unconventional resources. Our key focus areas include the North Sea, Athabasca oil sands, Canadian coalbed methane, Gulf of Mexico, offshore West Africa and the Middle East—areas we believe have attractive fiscal terms and significant remaining opportunity, and where we have some competitive advantage.

In 2006, we invested more than $3.4 billion in capital expenditures, mostly in multi-year development projects and long cycle-time exploration. In 2007, we plan to invest $2.8 billion in our oil and gas and Syncrude assets. About 34% of this is focused on multi-year development projects, 28% on core assets to sustain production and provide cash flow, and 24% on drilling high-impact exploration wells and building our acreage position. The rest will be spent on early stage development activities.

2006 Investment Program

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	1,050	74	45	–	1,169
United Kingdom	552	14	62	31	659
Yemen	–	–	37	145	182
United States	31	–	177	387	595
Canada	167	15	118	140	440
Other Countries	–	20	52	8	80
Syncrude	49	–	–	37	86
	1,849	**123**	**491**	**748**	**3,211**
Marketing, Corporate and Other	–	–	–	197	197
Total Capital	**1,849**	**123**	**491**	**945**	**3,408**
As a % of Total Capital	54%	4%	14%	28%	100%

2007 Estimated Capital

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	500	170	–	–	670
United Kingdom	300	–	125	200	625
Yemen	–	–	50	100	150
United States	–	60	325	200	585
Canada	200	–	50	150	400
Other Countries	–	170	150	–	320
Syncrude	–	–	–	50	50
	1,000	**400**	**700**	**700**	**2,800**
Marketing, Corporate and Other	–	–	–	100	100
Total Capital	**1,000**	**400**	**700**	**800**	**2,900**
As a % of Total Capital	34%	14%	24%	28%	100%

2007 Estimated Capital

Major and Early Stage Development Projects

Approximately 58% of our 2006 capital was directed towards early stage and major development projects including Buzzard, Long Lake, Syncrude Stage 3 and CBM.

Synthetic

In 2006, we invested approximately $1.2 billion to develop our insitu oil sands resource. This included approximately $1.1 billion invested at our first phase of Long Lake. The SAGD facilities are in the final stages of commissioning and start up and we expect steam injection to commence at the end of the first quarter of 2007, with bitumen production rates ramping up to peak rates over a 12 to 24 month period. Upgrader module fabrication is largely complete and over 95% of the modules are on site. Construction of the upgrader is approximately 80% complete and start up is scheduled for late 2007. Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (30,000 bbls/d net to us) of premium synthetic crude which we expect to reach by late 2008 or early 2009.

We have a number of major development projects at various stages of completion.

We are planning to increase synthetic crude oil production to 240,000 bbls/d (120,000 bbl/s net to us) over the next decade. We plan to sequentially develop our oil sands leases with additional 60,000 bbls/d (30,000 bbls/d net to us) phases using the same technology and design as Long Lake phase 1. We are currently progressing phase 2 development. We have completed seismic and core hole drilling programs and we have ordered several major vessels.

United Kingdom

At Buzzard, we installed the utilities and production topsides, drilled the initial development wells and completed hook-ups and project commissioning. Buzzard came on stream in early January 2007 and production is ramping up. The facilities have the capacity to process up to 200,000 bbls/d of oil and 60 mmcf/d of gas, including the removal of hydrogen sulphide. Based upon recent drilling results, we have experienced more well-to-well variability in the concentration of hydrogen sulphide than previously seen. We expect existing equipment and processes will allow us to manage this variability for at least the first two or three years of production. As we continue to produce and acquire reservoir information, we will determine whether additional equipment will ultimately be required. We have a 43.2% interest in Buzzard and operate the project.

Elsewhere in the North Sea, we are progressing the development of the Ettrick field. Production at Ettrick is expected to commence in the first half of 2008, with our share reaching approximately 16,000 boe/d. Development is approximately 30% complete and includes drilling three production wells tied back to a floating production, storage and off-loading vessel. We have an 80% interest in Ettrick.

Canada

In Canada, we are developing the first commercial CBM project from Mannville coals in the Fort Assiniboine area of Alberta. In 2006, we invested $237 million in exploration and development activities on our CBM lands, of which $181 million was associated with development. We plan to increase our CBM production to at least 150 mmcf/d by 2011.

During the year, we acquired over 100 sections of land in an emerging shale gas play in western Canada. We plan to initiate a drilling and evaluation program in 2007 to demonstrate the feasibility of this opportunity.

Other Countries

On Block OPL-222, offshore West Africa, Nigerian authorities have provisionally approved the Usan Field Development Plan. Basic engineering of the facilities is complete and tendering of contracts for all major components is proceeding. The development plan includes a floating production, storage and off-loading vessel with storage capacity of two million barrels, capable of handling peak production rates of 160,000 bbls/d of oil. We expect the Usan development to be formally sanctioned in 2007, with first production as early as 2010. We have a 20% interest in the exploration and development of this block.

Syncrude

At Syncrude, we completed the Stage 3 expansion during the year. Start up was initially delayed by the emission of odours from the flue gas desulphurizer plant but modifications to eliminate the odours were completed and the expansion started up in late August. The Stage 3 expansion increases our production capacity by 8,000 bbls/d.

New Growth Exploration

We invested approximately 14% of our 2006 capital in new growth exploration, including seismic data acquisition. We had exploration success in the Gulf of Mexico at Alaminos Canyon Block 856 (Great White West) and Ringo, and at Golden Eagle in the UK North Sea.

At Alaminos Canyon 856, we are evaluating development options following a two-well exploration drilling program earlier in the year. This block is located approximately 240 miles south of Houston and is immediately west of the Great White discovery. We have a 30% interest in this discovery.

At Ringo, we are evaluating a sub-sea tie-back to nearby facilities, which could be on stream in late 2008. We have a 50% interest in this discovery.

We recently completed drilling operations at our Golden Eagle prospect in the UK North Sea. The discovery well was drilled to a depth of approximately 7,500 feet and encountered hydrocarbons. A successful sidetrack well was drilled to appraise the accumulation and we are currently evaluating development options. We have a 34% operated interest in Golden Eagle.

Our exploration program continues to deliver results with new finds in the Gulf of Mexico and North Sea.

In 2006, we participated in the Norwegian exploration bid round and were recently awarded four licenses. The licenses are in water depths from 1,000 to 1,300 feet and are located between 30 and 100 miles offshore Norway, situated close to existing infrastructure. In 2007, we plan to invest in additional seismic and geological studies in this region.

Core Asset Development

We direct our capital investment in our maturing assets to extract maximum value over the remaining life of the assets. In the Gulf of Mexico, we began producing from an additional development well at Aspen in late December. Based on results from this well, we see further opportunities in the Aspen field and are currently sidetracking one of our existing Aspen wells to exploit deeper sands. We have a 100% interest in Aspen.

During the year, we commenced power production from our Soderglen 70 megawatt wind farm in southern Alberta. The wind farm comprises 47 wind towers, each with a 1.5 megawatt turbine. We have a 50% interest in this project.

FINANCIAL RESULTS

Year-to-Year Change in Net Income

(Cdn$ millions)	2006 vs 2005	2005 vs 2004
Net Income for 2005 and 2004 [1]	**1,140**	**793**
Favourable (unfavourable) variances: [2]		
Production Volumes, After Royalties		
Crude Oil	(245)	39
Natural Gas	(55)	(55)
Change in Crude Oil Inventory	(74)	4
Total Volume Variance	(374)	(12)
Realized Commodity Prices		
Crude Oil	325	648
Natural Gas	(133)	165
Total Price Variance	192	813
Oil and Gas Operating Expense		
Conventional	13	(64)
Syncrude	(35)	(27)
Total Operating Expense Variance	(22)	(91)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas and Syncrude	(48)	(308)
Other	4	(19)
Total Depreciation, Depletion, Amortization and Impairment Variance	(44)	(327)
Exploration Expense	(111)	(5)
Energy Marketing Contribution	336	49
Chemicals Contribution	(12)	31
General and Administrative Expense	254	(510)
Interest Expense	44	46
Current Income Taxes	(29)	(91)
Future Income Taxes	(549)	353
Other		
Block 51 Arbitration	(151)	–
Business Interruption Insurance Proceeds	152	(8)
Gains from Divestiture Programs	(418)	418
Increase (Decrease) in Fair Value of Crude Oil Put Options	185	(252)
Other	8	(67)
Net Income for 2006 and 2005 [1]	**601**	**1,140**

Notes:

1 2005 and 2004 includes results of discontinued operations (see Note 14 to our Consolidated Financial Statements)

2 All amounts are presented before provision for income taxes.

Significant variances in net income are explained in the sections that follow.

OIL & GAS AND SYNCRUDE

Production

	2006		2005		2004	
	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Oil and Liquids (mbbls/d)						
Yemen	92.9	51.8	112.7	60.6	107.3	53.5
Canada [2]	20.0	15.8	29.2	22.6	36.2	28.2
United States	17.0	15.0	22.2	19.6	30.0	26.5
United Kingdom	16.9	16.9	12.6	12.6	1.5	1.5
Australia [3]	–	–	–	–	2.7	2.5
Other Countries	6.3	5.7	5.6	5.1	5.3	4.7
Syncrude (mbbls/d) [4]	18.7	16.9	15.5	15.3	17.2	16.6
	171.8	122.1	197.8	135.8	200.2	133.5
Natural Gas (mmcf/d)						
Canada [2]	108	91	124	101	146	115
United States	111	94	116	99	148	126
United Kingdom	20	20	23	23	3	3
	239	205	263	223	297	244
Total (mboe/d)	**212**	**156**	**242**	**173**	**250**	**174**

Notes:

1 *We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.*

2 *Includes the following production from discontinued operations. See Note 14 to our Consolidated Financial Statements.*

	2006	2005	2004
Before Royalties			
Oil and Liquids (mbbls/d)	–	6.7	11.7
Natural Gas (mmcf/d)	–	24	47
After Royalties	–		
Oil and Liquids (mbbls/d)	–	5.3	9.0
Natural Gas (mmcf/d)	–	17	33

3 *Comprises production from discontinued operations. See Note 14 to our Consolidated Financial Statements.*

4 *Considered a mining operation for US reporting purposes.*

2006 vs 2005—Lower production decreased net income by $374 million

Production before royalties decreased 12% from 2005, while production after royalties decreased 10%. Our 2006 production excludes volumes from our Canadian oil and gas properties that were sold in the third quarter of 2005. Removing the impact of these property dispositions, production before and after royalties declined 8% and 5%, respectively.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2005 Production	242	173
Canada—Disposition of Properties	(11)	(8)
	231	165
Production changes		
Yemen	(20)	(9)
Canada	(1)	(1)
United States	(6)	(5)
United Kingdom	4	4
Colombia	1	1
Syncrude	3	1
2006 Production	**212**	**156**

In 2007, we expect to grow our annual production rate after royalties approximately 50% compared to 2006 to between 230,000 and 260,000 boe/d after royalties (275,000 and 305,000 boe/d before royalties). Increases are expected to come from Buzzard in the North Sea (which commenced production January 7, 2007), from the Gulf of Mexico and a full year of production from the Stage 3 expansion at Syncrude. Also, steam injection at Long Lake is expected to begin at the end of the first quarter in 2007, with bitumen production ramping up until the upgrader is scheduled to commence synthetic crude oil production late in 2007. Anticipated field declines in Yemen will partially offset these expected increases.

Our production after royalties is expected to grow approximately 50% in 2007, with incremental volumes from Buzzard, the Gulf of Mexico, Syncrude Stage 3 and Long Lake.

Production volumes discussed in this section represent our working interest before royalties.

Yemen

Yemen production decreased 18% from 2005. Production from Masila decreased 19% reflecting the maturity of the field and the impact of a reduced development drilling program. In 2006, we drilled 28 development wells, eight fewer than in 2005. Strong initial rates from new wells, combined with well optimizations, helped to minimize expected production declines. Base declines at Masila are expected to continue as we maximize recovery of the remaining reserves on the block prior to expiry of our license in 2011. We plan to drill 14 development wells and continue our well optimization program in 2007.

On Block 51, production from the East Al Hajr field declined 12%. In the first quarter of 2006, we commissioned the permanent central processing facilities on the block. Lower than expected initial rates on new wells and higher than anticipated decline rates contributed to the decrease from 2005. During the year, we drilled 24 development wells and nine development wells are planned for 2007.

We expect our share of total production from Yemen to average between 60,000 and 75,000 bbls/d in 2007.

Canada

Production in Canada decreased 24% from the previous year, primarily as a result of the sale of conventional oil and gas properties in Alberta, British Columbia and Saskatchewan. Removing the effect of the dispositions, production decreased 3% from 2005. Natural field declines of 7,600 boe/d were offset by capital investment in our heavy oil and natural gas assets, contributing 5,500 boe/d in new production. Gas production is increasing at our coalbed methane projects in Alberta as existing wells continue to de-water and we bring more wells on stream. In 2007, we expect to drill 165 infill wells, continue optimization activities on our conventional assets and work on developing new technologies to increase recoveries on our heavy oil properties.

We expect 2007 production to average between 45,000 and 50,000 boe/d in Canada with the commencement of production of premium synthetic crude oil at Long Lake and additional coalbed methane volumes.

United States

Gulf of Mexico production declined 14%, or about 6,000 boe/d from 2005. Lower production from Aspen due to natural declines contributed approximately 5,400 boe/d of the decrease. An additional Aspen development well was brought on stream in December 2006. This well was expected to come on stream earlier in the year but damage to the drilling rig from a work-boat accident delayed completion of the well. We are currently side-tracking one of the wells and expect it to be on stream by mid 2007. In 2007, we expect production from the Aspen field to average between 15,000 and 20,000 boe/d. Gunnison production remained strong, accounting for 30% of our production from the Gulf of Mexico. Development of the Dawson Deep discovery was completed and tied-back to our Gunnison SPAR in July. The Wrigley development was delayed by the tight rig market in the Gulf, but completion is progressing and the development is expected to come on stream in the first half of 2007, with production rates anticipated of 3,200 boe/d.

The effects of Hurricanes Katrina and Rita continued to be felt in 2006 as we slowly restored production from fields shut-in due to damage received in 2005. Production from Vermilion 321 was restored in September 2006. At year end, Vermilion 340 remains shut-in from damage to the sub-surface pipeline system. This production was restored in early 2007 (400 boe/d). During the year, we received $80 million of business interruption insurance proceeds related to the 2005 hurricanes.

In 2007, we expect production to average between 45,000 and 55,000 boe/d in the Gulf of Mexico.

United Kingdom

Production in the UK increased 23%, or 3,800 boe/d from 2005, primarily as a result of less downtime on the Scott platform and new production from our non-operated Farragon field. In 2005, our production was reduced by two generator failures on the Scott platform. During 2006, we received $74 million in business interruption proceeds related to these failures. Our 2006 production was lower than we expected as planned maintenance work on the Scott platform flare tip took longer than anticipated and operating capacity was reduced by maintenance activities on the SAGE export pipeline.

With Buzzard on stream, we expect UK production to average between 90,000 and 100,00 boe/d in 2007.

Final commissioning of the facilities at Buzzard was delayed by inclement weather in the North Sea late in the year. Buzzard began production on January 7, 2007. The delay has no impact on our ramp-up plans and peak production of 85,000 boe/d is expected to be achieved in the second quarter of 2007.

In 2007, we plan to drill and complete eight production and three injection wells at Buzzard and three development wells in the Scott/Telford area. We expect our total year production from our North Sea assets to average between 90,000 and 100,000 boe/d in 2007. This compares to the 19,000 boe/d these assets produced when we purchased them in late 2004.

Other Countries

Production from the Guando field in Colombia was consistent with 2005. We maintained production rates from two infill drilling programs, bringing 15 additional wells on stream during the year. We expect to maintain production rates in Colombia in 2007.

Syncrude

At Syncrude, production increased 21% from 2005, but was lower than expected. The start-up of the Stage 3 expansion was delayed by emission of odours from the flue gas desulphurizer plant. Production from the Stage 3 expansion began in early May and was approaching design capacity rates prior to shutting in as a result of the odours. Modifications to eliminate the problem were completed during the summer and the facilities were restarted in late August. Late in the year, a turnaround on coker 8-2 reduced production by approximately 6,000 bbls/d. The turnaround was completed early in 2007.

Strong realized prices on production have enabled us to fully recover capital costs at Syncrude including costs associated with the Stage 3 expansion. Consequently, our Syncrude royalty in 2006 increased from a 1% gross revenue royalty to a 25% net revenue royalty. As a result of the increased royalty rate, we receive lower net production relative to our working interest production volumes.

In 2007, we expect our total-year production from Syncrude to average between 20,000 and 25,000 bbls/d.

2005 vs 2004—Lower production decreased net income by $12 million

Production before royalties declined 3% during 2005, while production after royalties remained consistent with 2004 levels. New royalty-free production from the UK North Sea partially offset the sale of higher-royalty production from Canada. We sold Canadian production during 2005 to reduce debt that financed our acquisition of offshore oil and gas assets in the North Sea. Production was lower as a result of hurricane activity in the Gulf of Mexico in the second half of 2005. Removing the impact of the Canadian asset sales and the lost volumes attributable to Hurricanes Katrina and Rita, our 2005 production before royalties would have increased 3% from 2004.

Commodity Prices

	2006	2005	2004
Crude Oil			
West Texas Intermediate (WTI) (US$/bbl)	66.22	56.58	41.40
Differentials [1] (US$/bbl)			
Heavy Oil - LLK	21.79	20.82	13.53
MARS	7.34	6.59	6.15
Masila	3.00	5.71	4.84
Dated Brent	1.08	2.20	–
Producing Assets (Cdn$/bbl)			
Yemen	71.57	62.07	47.59
Canada	42.79	40.51	36.60
United States	65.80	57.63	46.60
United Kingdom	71.19	60.55	46.81
Australia	–	–	51.22
Other Countries	66.09	59.96	43.07
Syncrude	72.32	71.00	52.80
Corporate Average (Cdn$/bbl)	67.50	58.98	45.90
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	6.99	8.99	6.19
AECO (Cdn$/mcf)	6.62	8.04	6.44
Producing Assets (Cdn$/mcf)			
Canada	6.49	7.51	5.76
United States	7.86	10.56	7.89
United Kingdom	7.43	7.86	8.28
Corporate Average (Cdn$/mcf)	7.18	8.89	6.85
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	**62.92**	**57.97**	**44.94**
Average Foreign Exchange Rate–Canadian to US Dollar	0.8818	0.8253	0.7683

Note:

1 These differentials are a discount to WTI.

2006 vs 2005—Higher realized prices increased net income $192 million

Average WTI was 17% higher from the prior year, increasing our average realized crude oil price 14% to $67.50/bbl. Our realized natural gas price fell 19% from 2005, while NYMEX decreased 22% in the same period. The full impact of the increase in WTI was not reflected in our higher realized crude oil price as the Canadian dollar strengthened relative to the US dollar. The impact of the weaker US dollar was offset by narrower crude oil differentials. The weaker US dollar reduced net sales by approximately $250 million, and reduced our realized crude oil and natural gas prices by approximately $4.85/bbl and $0.50/mcf, respectively as compared to 2005.

Crude Oil Reference Prices

Crude oil prices remained strong for most of 2006, with WTI reaching new highs in July before finishing the year at US$61.05/bbl, roughly where it began. WTI traded at an average of US$66.22/bbl for the year, with a trading range of between US$54.86/bbl and US$78.40/bbl, where it peaked on July 14. The steady decline in crude prices from August to the end of the year was largely driven by warm weather, above average crude oil inventories, concerns over the US economy, the perceived reduction of geopolitical tensions in the Middle East and institution-led sell offs in the crude oil markets.

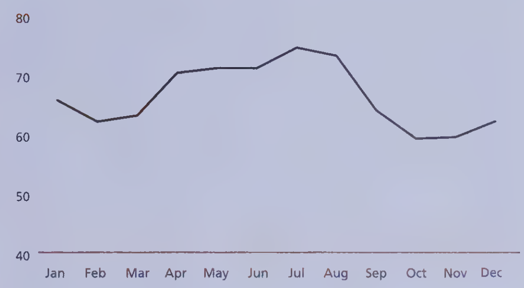
Weather has become an increasingly significant factor in the pricing of crude oil. In North America, a mild 2005/2006 winter followed by an uneventful hurricane season in the Gulf of Mexico and a forecast for a warmer than normal 2006/2007 winter season due to the warming effect of El Nino have put downward pressure on prices. The resulting reduced demand has helped push crude oil inventories to levels higher than the five-year average. In addition, concerns over a slowdown in the US economy due to the weakening of the US housing market have depressed crude oil prices further.

WTI reached record highs during 2006, increasing our realized crude oil prices.

Geopolitical events were a dominant theme through the first eight months of the year. Tensions in the Middle East as a result of Iran's uranium enrichment program, on-going violence in Iraq, fighting between Israel and Hezbollah militants in Lebanon, supply outages in Nigeria caused by continued violence and the nationalization of Venezuela's energy industry contributed to increased prices and greater market volatility. Towards the end of the year, however, geopolitical tensions have been discounted by the market following an end to the conflict in Lebanon and doubts the US will move against Iran.

A number of oil and gas producers have put option price protection programs in place at WTI strike prices ranging from US$45 to US$60/bbl. With falling crude oil prices, these programs get closer to being "in the money". This caused a sell-off in the crude oil markets by various institutions that wrote these options as they attempted to manage their option exposures. This sell-off contributed to the downward pressure on crude prices.

2006 WTI Monthly Average Oil Price (US$/bbl)



To mitigate the bearish sentiments for crude oil, OPEC has shown a commitment to its US$50 – $55/bbl basket price by agreeing to reduce production by 1.2 million barrels a day from November 1 and by a further 500,000 barrels a day from February 1, 2007. On the demand side, global oil demand growth remains moderate and is expected to rise by 1.5 million barrels per day in 2007 to 86 million barrels a day. This growth comes mainly from China and India. We expect this demand increase and the commitment from OPEC to lower production to stabilize crude oil prices in the near term.

Since the beginning of 2007, WTI has dropped to a low of US$49.90/bbl, but has since rebounded to approximately US$59/bbl in early February.

Crude Oil Differentials

In Canada, heavy crude oil differentials averaged US$21.79/bbl (33% of WTI) for the year, compared to $20.82/bbl (37% of WTI) in 2005. Differentials narrowed in the summer, as demand increased for heavy blends relative to light blends. This reflected normal seasonal narrowing as we headed into the summer asphalt season. Typically, heavy crude oil differentials widen going into the fourth quarter but this year, they maintained their summer levels following the late-year falloff in WTI. In addition, heavy crude oil differentials are tighter than usual this winter since OPEC cuts tend to be heavy barrels. This increases the value of heavy barrels relative to lighter barrels.

The US Gulf Coast Mars differential widened, averaging US$7.34/bbl in 2006 as compared to US$6.59/bbl in 2005. This was primarily due to higher WTI prices, temporary declines in demand due to refinery maintenance schedules and increased competition from Canadian heavy crude down the Spearhead pipeline into Cushing, Oklahoma and the Pegasus pipeline into Nederland, Texas. Late in the year, Mars differentials narrowed in response to falling WTI prices and OPEC production quota cuts.

The Yemen Masila differential narrowed substantially relative to WTI during 2006, averaging US$3.00/bbl compared to US$5.71/bbl last year. This largely reflects the impact of stronger Brent pricing since Masila crude is priced off Brent, coupled with continued strong Asian demand.

The Brent/WTI differential strengthened during 2006, creating strong crude oil pricing for our North Sea barrels.

The Brent/WTI differential strengthened during 2006 averaging US$1.08/bbl as compared to US$2.20/bbl in 2005, resulting in a solid crude oil price for our North Sea barrels. The spread between WTI and Brent broke away from historical norms where WTI usually trades at a premium of US$1.50/bbl to US$2.00/bbl. Several times during the year, WTI traded at a discount to Brent. This was caused by weak US demand during a heavier than usual maintenance season, coupled with high US crude inventory levels as production from the US Gulf Coast came back on stream following damage caused by Hurricanes Katrina and Rita in 2005. On-going production outages in Nigeria also helped to push Brent up relative to the North American WTI benchmark. Near the end of the year, Brent gained more upside support due to the production quota cut from OPEC. OPEC cuts have a more immediate impact on Brent relative to WTI given the shorter transit time of Brent to world markets.

Natural Gas Reference Prices

Natural gas prices averaged US$6.99/mmbtu, 22% below 2005 levels. NYMEX reached record price and volatility levels in late 2005, driven mainly by the impact of hurricanes Katrina and Rita and speculation around the 2005/2006 North American winter season. In 2006, the mildest January temperatures on record were experienced in several key North American natural gas consuming regions which resulted in a weakening of NYMEX. This created a significant gas storage overhang. Prices remained soft throughout the year reflecting high storage levels, an uneventful hurricane season and a mild 2006/2007 winter prediction due to the warming effect of El Nino. Lack of sustained cold temperatures heading into 2007 will discourage storage withdrawals, which puts further downward pressure on prices.

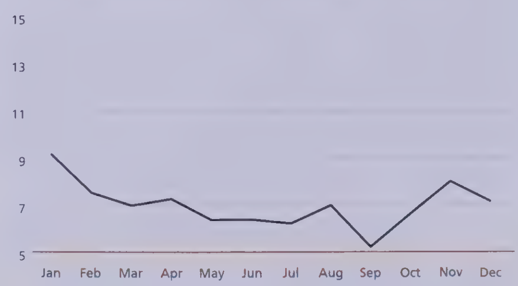
2005 vs 2004—Higher realized prices added $813 million to net income

Crude oil prices remained strong in 2005 reaching new highs and new levels of volatility. While global demand was moderate and supply levels adequate, the stability and security of long-term supply remained a concern, along with tightening refining capacity worldwide.

Natural gas prices reached record highs and experienced increased volatility. Prices early in the year were propped up by strong oil prices. The disruptions caused by the hurricanes pushed North American gas prices to new highs. The volatility did not end with the hurricane activity, but continued into the winter, as markets speculated on the impact of a cold or mild winter on tight supply. Prices peaked on December 13, 2005 with NYMEX gas settling at US$15.38/mmbtu.

The full benefit of higher benchmark prices wasn't reflected in our realized prices because of the weaker US dollar in 2005. All of our oil sales and most of our gas sales are denominated in, or referenced to, US dollars. As a result, the weaker US dollar decreased net sales for the year by approximately $270 million, and reduced our realized crude oil and natural gas prices by approximately $4.40/bbl and $0.65/mcf, respectively, compared to 2004.

2006 NYMEX Monthly Average Natural Gas Prices (US$/mmbtu)



Operating Expenses

(Cdn$/boe)	2006 Before Royalties [1]	2006 After Royalties	2005 Before Royalties [1]	2005 After Royalties	2004 Before Royalties [1]	2004 After Royalties
Conventional Oil and Gas						
Yemen	4.45	8.11	3.63	6.75	2.80	5.64
Canada	10.31	12.73	8.21	10.34	7.12	8.98
United States	8.17	9.45	6.35	7.33	5.30	6.12
United Kingdom	11.28	11.28	14.90	14.90	8.26	8.26
Australia	–	–	–	–	32.94	35.73
Other Countries	2.87	3.13	5.55	6.08	3.76	4.09
Average Conventional	6.95	9.69	6.03	8.70	5.13	7.59
Synthetic Crude Oil						
Syncrude	27.53	30.43	26.95	27.22	19.89	20.61
Average Oil and Gas	8.77	11.96	7.36	10.34	6.15	8.83

Note:

1 *Operating expenses per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.*

2006 vs 2005—Higher operating expenses decreased net income by $22 million

In Yemen, operating costs on a per-unit basis are increasing as fixed costs from our central processing facilities, combined with increased water handling costs, are spread over lower production volumes. At Masila, lower production and increased service rig activity required to minimize production declines, combined with the costs associated with the replacement of a single point mooring system used to load oil onto tankers, increased our corporate average by $0.20/boe. Block 51 operating costs increased our corporate average by $0.22/boe, reflecting higher manpower costs, increased water handling costs at the new facilities, maintenance costs associated with equipment repairs and power outages, and increased fuel consumption and fuel prices. We expect Yemen operating costs per barrel to continue to increase as our production declines.

Following the sale of Canadian conventional oil and gas properties in 2005, we have proportionately higher production from our heavy oil properties, which have higher operating costs compared to the lighter oil production we sold. Canadian operating costs increased our corporate average by $0.18/boe. We are focused on increasing recovery rates from our heavy oil properties by developing new technologies.

Operating costs in the Gulf of Mexico increased from last year due to industry cost pressures caused by the strong commodity price environment and the 2005 hurricane season. Lower production volumes and workovers on our shelf properties at the start of the year increased our corporate average by $0.39/boe.

With the sale of Canadian production in 2005, barrels from the North Sea are contributing a higher percentage of our total production. As the North Sea has higher operating costs than our average cost per barrel, the change in production mix has increased our corporate average by $0.32/boe. This was offset by lower operating costs relative to 2005, as operating expenses last year included repair costs related to turbine failures. This reduced our corporate average by $0.26/boe. We expect our North Sea operating costs to decrease on a per-unit basis in 2007, with increased low-operating cost production expected from Buzzard.

We expect 2007 operating costs to decrease on a per-unit basis with increased low-operating cost production from Buzzard.

Syncrude increased our corporate average operating costs by $0.72/boe as a result of maintenance activities and the turnaround of a coker during the first quarter of 2006, combined with costs related to start-up of the Stage 3 expansion.

The stronger Canadian dollar decreased our US-dollar denominated operating costs, reducing our corporate average by $0.38/boe, compared to 2005.

2005 vs 2004—Higher operating expenses decreased net income by $91 million

In 2005, higher operating costs reflect the change in our profile as more of our production came from higher-cost areas such as the North Sea and from Canadian heavy oil following the Canadian property sales completed that year. Operating costs were negatively impacted by storm-related costs and maintenance activities. In addition, high levels of industry activity and higher energy costs, driven by record commodity prices, increased our operating costs.

Our operations at Masila in Yemen reflect the maturing asset base and have higher operating costs, mainly from increased service rig activity to minimize production declines. These higher costs added $0.09/boe to our corporate average. Block 51 operating costs were higher than Masila, reflecting the use of temporary production facilities. Higher operating costs from Block 51 increased our corporate average by $0.53/boe.

Industry cost pressures and the sale of conventional production increased our Canadian unit operating costs in 2005. Although we sold high-cost production relative to our corporate average, we expect our overall Canadian operating costs to increase as we have proportionately higher production from our heavy oil properties. These properties have higher operating costs compared to the lighter oil production that was sold.

In the Gulf of Mexico, lower volumes of higher-cost barrels at Aspen, along with $12 million of Aspen-1 intervention costs expensed in 2004, decreased our corporate average by $0.10/boe. Workovers on our shelf properties, coupled with lower production and property damage costs not covered by insurance, increased our corporate average by $0.05/boe from 2004.

Higher-cost North Sea production increased our corporate average unit costs by $1.14/boe. Our North Sea operating costs were higher than anticipated as a result of maintenance and repair work caused by generator failures in the second quarter and major maintenance turnaround and facilities upgrading at the Scott platform in the third quarter.

Our Australian operations ceased in late 2004 and the exclusion of these high-cost, late-life barrels reduced our corporate average by $0.57/boe. US-dollar denominated operating costs were lower when translated to Canadian dollars as a result of the weak US dollar. Our corporate average was reduced by $0.30/boe as a result.

Syncrude operating costs per boe were 35% higher than in 2004. Turnaround and maintenance costs accounted for half of the increase, as we completed major turnarounds on various upgrading units during the year. In addition, high levels of industry activity in the oil sands have put upward pressure on costs. When combined with higher energy costs required in the upgrading process, our corporate average increased by $0.34/boe.

Depreciation, Depletion, Amortization and Impairment (DD&A)

	2006		2005		2004	
(Cdn$/boe)	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Conventional Oil and Gas						
Yemen	9.67	17.61	8.56	15.93	4.35	8.77
Canada	11.22	13.84	9.26	11.67	9.02	11.37
United States [2]	16.28	18.84	15.39	17.77	12.93	14.93
United Kingdom	30.22	30.22	33.25	33.25	22.44	22.44
Australia	–	–	–	–	5.82	6.31
Other Countries	4.30	4.69	6.20	6.79	9.90	10.77
Average Conventional	13.12	18.30	11.78	17.00	7.87	11.64
Synthetic Crude Oil						
Syncrude	4.81	5.32	3.08	3.12	2.75	2.85
Average Oil and Gas	12.38	16.88	11.23	15.77	7.52	10.80

Notes:

1 *DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.*

2 *DD&A per boe excludes the impairment charge described in Note 6 of our Consolidated Financial Statements.*

2006 vs 2005—Higher oil and gas DD&A decreased net income by $48 million

Our 2006 DD&A expense includes $93 million ($1.21/boe) of impairment expense primarily related to two natural gas producing properties in the Gulf of Mexico. The impairment was caused by disappointing development programs and negative year-end reserve revisions. The carrying values of the impaired properties have been reduced to their estimated fair value. In addition, our 2006 DD&A expense includes $15 million (2005—$58 million) relating to the write down of a portion of our purchase price allocation to unproved properties purchased in the North Sea as a result of unsuccessful exploration activities. Our 2006 average depletion rate excluding impairment charges is $12.38/boe, 10% above our 2005 average.

In Yemen, we began depleting the permanent production facilities on Block 51 during the year. Strong crude oil prices allowed us to continue to maximize the recovery of the costs we paid on behalf of the government. This increased our corporate average by $0.64/boe.

The strong Canadian dollar reduced our corporate DD&A rate by $0.72/boe from 2005.

The increased Canadian depletion rate reflects the depletion of costs associated with our coalbed methane projects in central Alberta. Our corporate average is higher by $0.35/boe as a result. We expect our depletion rate for our coalbed methane projects to decline as the wells de-water and we are able to recognize additional reserves. Depletion rates for our deep-water assets in the Gulf of Mexico increased our average by $0.28/boe primarily as a result of reserve revisions late in 2005.

Our depletion rate for our North Sea assets is higher than our average, primarily from the allocation of the purchase price we paid for these assets in 2004. Our corporate average is increasing as the North Sea becomes a larger proportion of our total production and from lower production in Canada following the sale of conventional oil and gas assets in 2005. This change increased our corporate average by $0.42/boe. We expect our corporate average will continue to increase in 2007 as we begin to deplete Buzzard.

The Stage 3 expansion at Syncrude began producing during the year and we started depleting these assets in 2006. This increased our corporate average by $0.23/boe.

The strong Canadian dollar reduced our DD&A expense relative to 2005 as the depletion of our international and US assets is denominated in US dollars. This lowered our corporate average by $0.72/boe from last year.

2005 vs 2004—Higher oil and gas DD&A decreased net income by $308 million

Strong production volumes, new production from our North Sea assets and additional capital cost recovery from Block 51 in Yemen increased our oil and gas DD&A compared with 2004 levels. We also expensed $58 million related to unproved North Sea properties as a result of unsuccessful exploration activities.

Block 51 production in Yemen increased our corporate unit depletion by $2.21/boe from 2004 as a result of carried interest accounting for the recovery of Block 51 capital costs. Strong production and higher realized oil prices have resulted in faster recovery of capital costs we paid on behalf of the government.

Our Canadian depletion rate per unit has increased slightly compared with 2004. Reserve revisions at the end of 2004 increased our 2005 heavy oil depletion rate. This increase was somewhat offset when we stopped depleting our Canadian assets held for sale in the second quarter, but continued to recognize related production. The disposition of these assets in the third quarter changed our asset mix and reduced our average annual corporate depletion rate by $0.23/boe.

Depletion rates in the Gulf of Mexico increased following reserve revisions in late 2004. Reduced volumes offset the increase in rates with minimal impact on our overall unit rate.

North Sea depletion increased our corporate average by $2.37/boe in 2005. The depletable carrying costs of our Scott, Telford and Farragon fields include an allocation of the purchase price we paid for these assets. In addition, our North Sea depletion includes $58 million relating to a partial write-off of our purchase price allocation to unproved properties subject to unsuccessful exploration activities.

The strengthening Canadian dollar offset these increases as the depletion of our international and US assets is denominated in US dollars. This lowered our corporate average by $0.70/boe compared with 2004.

Exploration Expense [1]

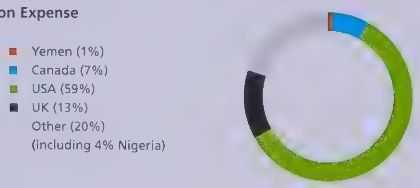
(Cdn$ millions)	2006	2005	2004
Seismic	128	53	73
Unsuccessful Drilling	169	143	125
Other	65	55	48
Total Exploration Expense	**362**	**251**	**246**
New Growth Exploration	491	456	266
Geological and Geophysical Costs	128	53	73
Total Exploration Expenditures	**619**	**509**	**339**
Exploration Expense as a % of Exploration Expenditures	58%	49%	73%

Note:
1 2005 and 2004 includes exploration expense from discontinued operations. See Note 14 to our Consolidated Financial Statements.

2006 vs 2005—Higher exploration expense reduced net income by $111 million

Our 2006 exploration activities were focused on drilling 20 wells, mostly in the Gulf of Mexico and the North Sea, and acquiring seismic data. We were successful at Great White West and Ringo in the Gulf of Mexico. In early 2007, we completed drilling operations at our Golden Eagle prospect on License P928 in the UK North Sea. The discovery well was drilled to a depth of approximately 7,500 feel and encountered hydrocarbons. A successful sidetrack well was drilled to appraise the accumulation and we are currently evaluating development options.

2006 Exploration Expense



Our unsuccessful drilling results were primarily in the Gulf of Mexico, where we expensed $135 million in dry hole costs. Early in the year, we expensed $49 million for the Pathfinder well, which found non-commercial quantities of hydrocarbons, after reaching a total depth of 31,196 feet. Unsuccessful wells on the shelf in the Gulf of Mexico include West Cameron 135 and 109 ($23 million and $14 million respectively) and Vermilion 65 ($15 million). During the year, we also expensed $29 million of capitalized costs related to Big Bend as it was determined that development was uneconomic and the block was relinquished. In the North Sea, dry hole costs included unsuccessful exploratory wells at Zanzibar ($10 million) and Black Cat ($7 million). Exploration expense also includes costs relating to Ukot South, offshore Nigeria, which encountered wet sands and was plugged and abandoned, and costs relating to three unsuccessful wells on Block 51 in Yemen.

Our geological and geophysical costs include $128 million of seismic data acquired during the year of which half relates to the Gulf of Mexico. The balance was spent on data relating to Canada, Norway, the North Sea, Nigeria and other international targets.

We continue to focus on large unconventional resource opportunities in Canada. In 2006, we acquired approximately 100 sections of prospective shale gas acreage in northeast British Columbia for $50 million, which we intend to evaluate in 2007.

We continue to grow our unconventional resource in Canada. In 2006, we acquired a sizeable shale gas land position in northeast BC.

In 2007, we plan to invest approximately $700 million to drill up to 19 exploration wells and acquire seismic data and access to new exploratory acreage. In the Gulf of Mexico we have four deep-water and five shelf-gas prospects planned, while we anticipate drilling five exploration wells in the North Sea. We expect to drill three exploration wells on Block 51 in Yemen, one deep-water exploration well offshore West Africa and one exploration well in Colombia.

2005 vs 2004—Higher exploration expense reduced net income by $5 million

Our 2005 exploration program was active, as we spent more than $500 million on 20 high-potential exploration wells in our key basins. In the Gulf of Mexico, Knotty Head, drilled to a depth of 34,189 feet, encountered hydrocarbons in multiple zones.

Our 2005 exploration expense includes costs associated with unsuccessful wells in the Gulf of Mexico, North Sea, offshore West Africa and Yemen. In the Gulf of Mexico, we expensed $44 million for the Vrede well. Vrede, a sub-salt prospect drilled to a total depth of 32,600 feet, encountered non-commercial quantities of hydrocarbons and was temporarily abandoned. We also wrote off costs relating to our Castleton dry hole, together with trailing costs related to the 2004 Crested Butte, Wind River and Fawkes wells. These wells, with the exception of Wind River, were located in the deep water.

In the North Sea, exploration expense includes costs relating to Black Horse, Polecat, Bennachie and Saracen. The Black Horse and Polecat wells encountered hydrocarbons, but insufficient to warrant stand-alone development. We will continue to evaluate these reservoirs in combination with other potential development projects that may be sanctioned in the future. Bennachie was abandoned after encountering no reservoir sands in the target zone. Saracen was written off earlier in 2005 as an unsuccessful exploratory well.

Internationally, we expensed costs related to four unsuccessful wells on Block 51 in Yemen and we abandoned our deep-water Efere well in Nigeria, as well as our K-2 well on Block K in Equatorial Guinea.

OIL & GAS AND SYNCRUDE NETBACKS

Netbacks are the cash margins, before general and administrative expenses, we receive for every equivalent barrel sold. The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

Before Royalties

	2006						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Royalties and Other	(32.32)	(7.80)	(7.53)	–	(5.51)	(6.93)	(17.68)
Operating Expenses	(4.45)	(10.31)	(8.17)	(11.28)	(2.87)	(27.53)	(8.77)
In-country Taxes [1]	(8.45)	–	–	–	–	–	(3.72)
Cash Netback	**26.35**	**22.87**	**40.42**	**55.53**	**57.71**	**37.86**	**32.75**

	2005						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Royalties and Other	(28.71)	(8.75)	(8.06)	–	(5.23)	(0.71)	(16.70)
Operating Expenses	(3.63)	(8.21)	(6.35)	(14.90)	(5.55)	(26.95)	(7.36)
In-country Taxes [1]	(7.17)	–	–	–	–	–	(3.34)
Cash Netback	**22.56**	**25.46**	**45.85**	**42.93**	**49.18**	**43.34**	**30.57**

	2004							
($/boe)	Australia	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	51.22	47.59	35.76	46.94	47.45	43.07	52.80	44.94
Royalties and Other	(4.00)	(23.98)	(7.40)	(6.29)	–	(3.49)	(1.84)	(13.65)
Operating Expenses	(32.94)	(2.80)	(7.12)	(5.30)	(8.26)	(3.76)	(19.89)	(6.15)
In-country Taxes [1]	–	(5.82)	–	–	–	–	–	(2.48)
Cash Netback	**14.28**	**14.99**	**21.24**	**35.35**	**39.19**	**35.82**	**31.07**	**22.66**

After Royalties

	2006						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Operating Expenses	(8.11)	(12.73)	(9.45)	(11.28)	(3.13)	(30.43)	(11.96)
In-country Taxes [1]	(15.40)	—	—	—	—	—	(5.07)
Cash Netback	**48.06**	**28.25**	**46.67**	**55.53**	**62.96**	**41.89**	**45.89**

	2005						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Operating Expenses	(6.75)	(10.34)	(7.33)	(14.90)	(6.08)	(27.22)	(10.34)
In-country Taxes [1]	(13.35)	–	–	–	–	–	(4.69)
Cash Netback	**41.97**	**32.08**	**52.93**	**42.93**	**53.88**	**43.78**	**42.94**

	2004							
($/boe)	Australia	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	51.22	47.59	35.76	46.94	47.45	43.07	52.80	44.94
Operating Expenses	(35.73)	(5.64)	(8.98)	(6.12)	(8.26)	(4.09)	(20.61)	(8.83)
In-country Taxes [1]	–	(11.72)	–	–	–	–	–	(3.57)
Cash Netback	**15.49**	**30.23**	**26.78**	**40.82**	**39.19**	**38.98**	**32.19**	**32.54**

Note:

1 *Comprises income taxes payable in Yemen that are included in the Government's share of profit oil.*

ENERGY MARKETING

(Cdn$ millions)	2006	2005	2004
Physical Sales [1]	40,920	37,873	28,554
Physical Purchases [1]	(39,925)	(36,988)	(28,074)
Net Financial Transactions [1]	314	(38)	128
Net Revenue	1,309	847	608
Transportation Expense	(789)	(641)	(451)
Other	20	(2)	(2)
Net Marketing Revenue	**540**	**204**	**155**
Contribution to Net Marketing Revenue by Product Type:			
North American Natural Gas	390	117	93
International Crude Oil	114	70	52
North American Power	16	8	4
Other	20	9	6
Net Marketing Revenue	**540**	**204**	**155**
Depreciation, Depletion, Amortization and Impairment	(12)	(11)	(10)
General and Administrative	(112)	(89)	(58)
Marketing Contribution to Income from Continuing Operations before Income Taxes	**416**	**104**	**87**
Natural Gas			
Physical Sales Volumes [2] (bcf/d)	5.4	4.9	4.9
Transportation Capacity (bcf/d)	3.3	4.0	3.5
Storage Capacity (bcf)	50	30	27
Crude Oil			
Physical Sales Volumes [2] (mbbls/d)	705	510	465
Storage Capacity (mbbls)	1,749	580	408
Power			
Physical Sales Volumes – Power [2] (MW/d)	4,388	2,548	1,191
Generation Capacity (MW/hr)	87	53	53
Value-at-Risk			
Year End	26	24	21
High	33	28	42
Low	17	11	17
Average	23	21	29

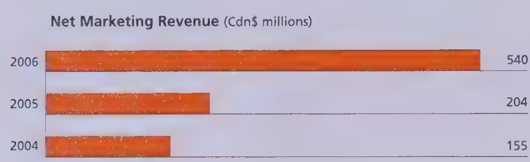
Notes:

1 *Marketing's physical sales, physical purchases and net financial transactions are reported net on the Consolidated Statement of Income as marketing and other.*

2 *Excludes intra-segment transactions.*

2006 vs 2005—Net marketing revenue increased net income by $336 million

Marketing had record results in 2006, with all groups achieving new highs or starting new businesses. The largest contribution continues to come from our North American natural gas marketing group where we capitalized on our asset-based trading strategy. Time and location spread trading generated most of our gas gains but we were also successful in generating revenues through the optimization of our transportation and storage capacity. Volatility within the North American gas markets created market inefficiencies for us to capitalize on. North American gas prices started 2006 at US$10.63/mcf and closed the year at US$6.30/mcf. Storage overhang and speculation around weather and possible hurricanes caused significant changes in prices during the year. We also took advantage of opportunities late in the year to add to our storage capacity.



Our crude oil marketing group also generated record results by successfully taking advantage of crude quality, location and time spreads. The group generated physical and financial trading gains by taking advantage of the contango (rising forward month prices) in the crude oil forward curve. In addition, we captured profits around quality spreads by diverting crude oil, or by blending to enhance the crude quality, and attract higher prices. While our strategies remained largely the same in 2006, we executed more transactions and added more capacity, particularly storage, during the year. With our newly established marine transportation capabilities, this group is well positioned to start marketing our Buzzard production in 2007.

Our power marketing group is the largest supplier of power to the commercial and industrial sector in Alberta and net revenue contributions exceeded expectations.

Our power marketing group is the largest supplier of power to the commercial and industrial sector in Alberta.

We continued our expansion into new markets during the year with acquisitions in the North American NGL trading business and a UK acquisition which positioned us in the UK and European gas and power markets.

Results from our marketing group vary between periods and historical results are not necessarily indicative of future results. Marketing results depend on a variety of factors such as market volatility, changes in time and location spreads, the manner in which we use our storage and transportation assets and the change in value of the financial instruments we use to hedge these assets.

2005 vs 2004—Net marketing revenue increased net income by $49 million

Marketing delivered strong results in 2005, with net revenue of $204 million. Our gas marketing group grew their net revenue to $117 million. We achieved these results through our continued focus on an asset-based trading strategy, using our transportation and storage capacity to take advantage of seasonal and locational pricing differences and market inefficiencies.

While 2005 was a profitable year, it was also volatile with hurricane activity in the Gulf of Mexico disrupting gas supply and infrastructure. This volatility caused us to recognize losses in the third quarter on financial contracts hedging our physical assets. However, we were able to recognize gains on our physical assets in the fourth quarter as we used our transportation capacity and sold gas from storage. This allowed us to recoup our third quarter losses and recognize $175 million of net revenue in the fourth quarter. We also generated profits from financial contracts that captured time and location spreads.

Our crude oil marketing group contributed $70 million of net revenue in 2005, an increase of 35% over 2004. Similar to prior years, we continued to capitalize on forward prices, as well as differences in crude qualities. In particular, in 2005, we took advantage of contango by successfully pricing our purchases lower than our sales, and by financially trading calendar spreads. We also captured profits around quality spreads by diverting crude oil, or by blending to enhance the crude quality, and attract higher prices.

Composition of Net Marketing Revenue

(Cdn$ millions)	2006	2005
Trading Activities	520	195
Non-Trading Activities	20	9
Total Net Marketing Revenue	**540**	**204**

Trading Activities

In marketing, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts not designated as hedges for accounting purposes using mark-to-market accounting and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is included with accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

We value derivative trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

Fair Value of Derivative Contracts

At December 31, 2006, the fair value of our derivative contracts not designated as hedges totalled $360 million (2005—$169 million). Below is a breakdown of this fair value by valuation method and contract maturity.

	Maturity				
(Cdn$ millions)	**< 1 year**	**1-3 years**	**4-5 years**	**> 5 years**	**Total**
Prices					
Actively Quoted Markets	190	(26)	(21)	–	143
From Other External Sources	216	(6)	13	(6)	217
Based on Models and Other Valuation Methods	–	–	–	–	–
Total	**406**	**(32)**	**(8)**	**(6)**	**360**

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	**Total**
Fair Value at December 31, 2005	169
Change in Fair Value of Contracts	576
Net Losses (Gains) on Contracts Closed	(385)
Changes in Valuation Techniques and Assumptions [1]	–
Fair Value at December 31, 2006	**360**
Unrecognized Gains on Hedges of Future Sale of Gas Inventory at December 31, 2006	25
Total Outstanding at December 31, 2006	**385**

Note:

1 *Our valuation methodology has been applied consistently year-over-year.*

As a physical energy marketer, we match the contract months of our derivative contracts with the contract months of our physical sales and purchases. As a result, the fair value of our derivative contracts as at December 31, 2006 includes amounts with no ongoing commodity price or foreign currency exchange risk. Excluding these amounts, the fair value of our derivative contracts at December 31, 2006 was $102 million.

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. While forward prices vary, the value of the contracts only varies to the extent they are economically exposed or unprotected. As most of our unrealized value is not economically exposed, we expect to realize the majority of this fair value.

More than 113% of the unrealized fair value relates to contracts that settle within 12 months. Contract maturities vary from a single day up to 12 years. Those maturing beyond one year primarily relate to North American natural gas positions. The relatively short maturity of our contracts, the high quality of our valuations from quoted markets and external sources and the limited economic exposure combine to lower our portfolio risk.

As part of our gas marketing strategy, we hold physical transportation and storage capacity contracts that allow us to take advantage of pricing differences between locations (i.e. west vs. east) and time periods (i.e. summer vs. winter). These capacity contracts have market value, similar to financial commodity contracts, as future margins realized depend on future prices and, more importantly, pricing differences. The market value of these capacity contracts varies depending on the change in future prices and pricing relationships. We routinely hedge the economic value of our capacity contracts using various types of derivative contracts, thereby limiting volatility in our economic results. Accounting rules, however, increase volatility in our reported results since they require us to recognize the change in fair value of derivative contracts hedging our capacity contracts, but do not allow us to recognize the change in fair value of the capacity contracts themselves until the contracts are used. As a result, when prices or pricing relationships change, we may be required to include gains or losses in our reported results in different periods even though our underlying economic results may be largely unchanged. At the end of 2006, unrecognized future commitments related to our transportation and storage capacity contracts was a loss of $81 million. This amount has been included in our contractual obligations, commitments and guarantees in the MD&A.

We have designated certain derivative contracts as accounting cash flow hedges of the future sale of our gas in storage. Mark-to-market gains and losses on these designated contracts are excluded from income until the underlying inventory is sold. At December 31, 2006, we had $25 million of unrecognized gains on these derivative contracts. These contracts have been valued from actively quoted markets and will settle within 12 months. In late 2006, we de-designated certain futures contracts that had been designated as cash flow hedges of future sales of our natural gas in storage. Gains of $65 million on the futures contracts have been deferred and are expected to be recognized in net income in the first quarter of 2007.

Non-Trading Activities

We enter into fee-for-service contracts related to transportation and storage of third-party oil and gas. We also earn income from our power generation facilities at Balzac and Soderglen. We earned $20 million from our non-trading activities in 2006 (2005—$9 million).

CHEMICALS

(Cdn$ millions)	2006	2005	2004
Net Sales	407	398	378
Sales Volumes (thousand short tons)			
Sodium Chlorate	487	493	506
Chlor-alkali	451	450	403
Operating Profit [1]	124	136	105
Operating Margin [2]	30%	34%	28%
Chemicals Contribution to Income from Continuing Operations Before Income Taxes	44	37	40
Capacity Utilization	95%	96%	95%

Notes:

1 *Total revenues less operating costs, transportation and other.*

2 *Operating profit divided by net sales.*

2006 vs 2005— Lower chemicals operating profit decreased net income by $12 million

Our investment in our chemicals business is held through our 61.4% interest in the Canexus Limited Partnership. While North American prices for sodium chlorate remained strong throughout 2006, sales volumes fell slightly from last year as a result of pulp mill closures. Chlor-alkali volumes and prices in North America remained steady. US-dollar denominated North American sales were reduced $12 million from the stronger Canadian dollar during 2006. Sales and operations from the Brazil plant remained solid as a result of strong demand from Aracruz Cellulose, our primary customer, and from the merchant market.

During the year, Canexus began an expansion of the Brandon, Manitoba plant, which benefits from low electricity rates.

Late in the year, Canexus commenced an expansion of the Brandon, Manitoba plant to increase capacity by 12% by early 2008. The Brandon plant benefits from low electricity rates in the province of Manitoba, where the electricity market is based on hydroelectric power and is regulated.

2005 vs 2004—Higher chemicals operating profit increased net income by $31 million

In the third quarter of 2005, we monetized a portion of our chemicals business by creating the Canexus Income Fund through an initial public offering (IPO), which raised net proceeds of $301 million. Canexus Limited Partnership, also raised US$167 million ($200 million) of bank debt. Canexus Limited Partnership used the proceeds from Canexus Income Fund's IPO and the bank debt, together with the issuance of 50.5 million exchangeable units of the Canexus Limited Partnership to Nexen, to purchase our chemicals operations. We have retained a 61.4% interest in the chemicals operations through our investment in Canexus Limited Partnership, and we recorded a gain of $193 million on the dilution of our interest.

Despite lower sales volumes, strong chlor-alkali prices and higher margins generated strong results for the chemicals business. Sodium chlorate volumes decreased compared with 2004 as a result of our decision in early 2005 to forego low-margin business consistent with our restructuring effort and the closure of our Amherstburg, Ontario plant. Sales and operations from the Brazil plant remained strong as a result of continued strong demand from Aracruz Cellulose, our primary customer in Brazil, and an expanded presence in the merchant market.

The weaker US dollar put pressure on our US-dollar denominated sales, reducing net sales by $13 million. During 2005, we purchased US-dollar foreign currency call options to mitigate our exposure to the weakening dollar. We generated $4 million of income as a result of these call options.

Our chemicals contribution was reduced by $12 million for an impairment charge relating to our chemicals plant in Amherstburg, which was closed in the third quarter of 2005.

CORPORATE EXPENSES

General and Administrative (G&A)

(Cdn$ millions)	2006	2005	2004
General and Administrative Expense before Stock-Based Compensation	345	302	206
Stock-Based Compensation [1]	210	507	93
Total General and Administrative Expense	**555**	**809**	**299**

Note:
1 *Includes tandem option plan, stock options for our US-based employees and stock appreciation rights plan.*

2006 vs 2005—Lower costs increased net income by $254 million

Our G&A expense before stock-based compensation increased 14% primarily from additional costs to expand our marketing operations into new markets. Acquisitions during the year enabled us to increase our NGL business in North America and to expand our European trading operations. Our G&A expense also includes higher variable compensation stemming from our marketing group's strong performance in 2006.

Total G&A expense decreased 31% in 2006 from lower stock-based compensation costs.

Changes in our share price creates volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation expense and related obligations. In 2006, our share price increased 16% from $55.42 to $64.20, creating over $2.3 billion of shareholder value. The expense represents approximately 9% of the increase in shareholder value. Cash payments to employees for our stock-based compensation programs were $119 million in 2006, a 61% increase over 2005.

2005 vs 2004—Higher costs reduced net income by $510 million

Our stock-based compensation expense in 2005 reflects the significant increase in the price of our common shares. Our share price increased 128% from $24.35 to $55.42, adding more than $8 billion of shareholder value. Notwithstanding this increase in our share price, cash payments to employees under our stock-based compensation programs only amounted to $74 million.

Our growing international presence and the expansion of our businesses increased our G&A costs during the year. Costs reflect more employees, additional travel, and higher compliance and governance costs, combined with increased variable incentive compensation stemming from our record results. We also incurred additional costs related to our disposition activities and the integration of our North Sea operations acquired in late 2004.

Interest

(Cdn$ millions)	2006	2005	2004
Interest	294	275	194
Less: Capitalized	(241)	(178)	(51)
Net Interest Expense	**53**	**97**	**143**
Effective Rate	6.3%	6.4%	6.6%

2006 vs 2005—Lower net interest expense increased net income by $44 million

Our financing costs have increased $19 million from 2005. Additional borrowings to finance our 2006 capital program increased financing costs by approximately $28 million. This was partially offset however, by the stronger Canadian dollar which decreased our US-dollar denominated interest by $16 million. The Canexus debt, consolidated with our results, increased our interest expense by $7 million.

The amount of interest we capitalized on our major development projects grew by $63 million, primarily from increased investment in the North Sea Buzzard project, at Long Lake and the Stage 3 expansion at Syncrude prior to its start-up. We expect interest capitalized on projects to decrease in 2007 as we ceased capitalizing interest on the Syncrude expansion in August 2006 and on Buzzard in January 2007. We expect to continue to capitalize interest on our Long Lake project prior to its completion in 2007. Our net interest expense is expected to increase once these projects are completed.

2005 vs 2004—Lower net interest expense increased net income by $46 million

We acquired our North Sea assets in late 2004. We partially financed this acquisition with US$1 billion of new long-term debt, increasing our interest costs by $87 million in 2005. Interest expense also increased $3 million relating to the Canexus debt consolidated with our results. However, the stronger Canadian dollar lowered our US-dollar denominated interest by $12 million. During the last two years, we have taken advantage of declining interest rates by replacing our higher-cost preferred securities with new long-term debt at lower rates.

Income Taxes

(Cdn$ millions)	2006	2005	2004
Current	368	339	248
Future	315	(234)	119
Total Provision for Income Taxes	**683**	**105**	**367**
Disclosed as:			
Provision for Income Taxes—Continuing Operations	683	234	317
Provision for Income Taxes—Discontinued Operations [1]	–	(129)	50
Total Provision for Income Taxes	**683**	**105**	**367**
Effective Rate	53%	8%	32%

Note:

1 See Note 14 to our Consolidated Financial Statements.

2006 vs 2005—Effective tax rate increases from 8% to 53%

In early 2006, the UK government substantively enacted increases to the supplementary tax rate on our North Sea oil and gas activities from 10% to 20%, effective January 1, 2006. This increased our future income tax liabilities, resulting in a charge of $277 million during the first quarter. During the second quarter, federal and certain provincial governments in Canada reduced corporate income tax rates. These rate reductions lowered our future income tax liabilities by $32 million. Our effective tax rate excluding the effect of these tax rate changes was 33%.

In 2006, an increase in the UK supplemental tax rate on oil & gas activities resulted in a future income tax expense of $277 million.

Current income taxes include cash taxes in Yemen of $286 million (2005—$296 million; 2004—$227 million). Our current income tax provision also includes federal and state taxes in the US, cash taxes in Colombia and capital taxes in Canada.

2005 vs 2004—Effective tax rate decreases from 32% to 8%

The recovery of future taxes payable of $234 million is attributable to the disposition of our oil and gas producing properties in Canada and the sale of our chemicals business to the Canexus Limited Partnership. As a result of the dispositions, we revalued our future income tax liabilities for the change in the underlying book and tax values. This revaluation resulted in the reduction of our future income tax liabilities. In addition, the disposition gains were taxed at lower capital gains tax rates. Removing the tax impact of the dispositions, the effective tax rate for our continuing operations was 32%.

Other

(Cdn$ millions)	2006	2005	2004
Block 51 Arbitration	(151)	–	–
Business Interruption Insurance Proceeds	154	2	10
Gain on Dilution of Interest in Chemicals Business	–	193	–
Gain on Disposition of Oil and Gas Assets included as Discontinued Operations	–	225	–
Increase (Decrease) in Fair Value of Crude Oil Put Options	(11)	(196)	56

During the year, a court of arbitration concluded that we breached an Area of Mutual Interest agreement with Occidental Petroleum Corporation (Occidental). As a result, Occidental was entitled to monetary damages. In late 2006, we agreed to settle the arbitration by agreeing to pay Occidental US$135 million as monetary damages. No further amounts are expected to be payable under the settlement.

In 2006, we received $154 million of business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005 and by generator failures in our UK operations in 2005.

As a result of the sale of our chemicals business to the Canexus Limited Partnership in 2005, we recorded a gain on the dilution of our interest from 100% to 61.4% of $193 million. Our gain on the 2005 sale of Canadian oil and gas properties in Alberta, British Columbia and Saskatchewan was $225 million.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2005 and 2006 to ensure base cash flow in those years while we invest in our major development projects. These options created an average floor price for this production of US$43.17/bbl in 2005 and US$38.17/bbl in 2006. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices cause gains or losses to be recorded on these options at each period end. A gain of $56 million was recorded in the fourth quarter of 2004, bringing the fair value of these options to $200 million. During 2005, a significant increase in forward crude prices reduced the value of these options by $196 million. Strong WTI prices in 2006 reduced the market value of these remaining options to nil and we expensed $4 million in 2006 as a result.

During 2006, we purchased put options on approximately 105,000 bbls/d of our 2007 crude oil production. These options establish a WTI floor price of US$50/bbl on these volumes, are settled annually and provide a base level of price protection without limiting our upside to higher prices. The put options were purchased for $26 million and are carried at fair value. We recorded a loss of $7 million during the year for the decrease in fair value.

OUTLOOK FOR 2007

In 2007, we plan to invest $2.9 billion in capital projects. Approximately 34% of this capital will be invested in development projects, which include Long Lake, coalbed methane in Canada, Ettrick in the North Sea, and Wrigley and Tobago in the Gulf of Mexico. We are also directing 14% of our 2007 capital to early-stage development projects expected to contribute production and cash flow growth beyond 2007. These include Knotty Head, Alaminos Canyon Block 856 (Great White West) and Ringo in the Gulf of Mexico, additional phases of oil sands in the Athabasca region and Block 222, offshore West Africa. We have allocated 24% of our capital to exploration opportunities in our growth areas. The remaining 28% of the 2007 capital will be invested to exploit potential in our existing producing assets and in other corporate assets.

Details of our 2007 capital investment program are included in the Capital Investment section of the MD&A.

Daily Production

We expect to grow annual production rates after royalties approximately 50% compared to 2006 to between 230,000 and 260,000 boe/d (275,000 and 305,000 boe/d before royalties). Our Buzzard development came on stream early January 2007 and we expect to achieve peak rates of 85,000 boe/d during the second quarter of 2007. Other contributions to our expected growth in 2007 are from the Gulf of Mexico, a full year of production from the Stage 3 expansion at Syncrude and bitumen production from Long Lake. Our annual production for 2007 is expected to be:

2007 Estimated Production

(mboe/d)	2007 Estimated Production Before Royalties	2007 Estimated Production After Royalties	2006 Production Before Royalties	2006 Production After Royalties
United States	45 – 55	38 – 48	36	31
United Kingdom	90 – 100	90 – 100	20	20
Yemen	60 – 75	35 – 45	93	52
Canada	45 – 50	38 – 42	38	31
Syncrude	20 – 25	18 – 20	19	17
Other International	6 – 7	5 – 6	6	5
Total	**275 – 305**	**230 – 260**	**212**	**156**

Cash Flow and Sensitivities

We expect to generate more than $3.3 billion in cash flow from operating activities in 2007 (before site restoration and geological and geophysical expenditures), assuming the following:

WTI (US$/bbl)	50.00
NYMEX Natural Gas (US$/mmbtu)	6.00
Oil & Gas and Syncrude Operating Costs (Cdn$/boe)	8.00
US to Canadian Dollar Exchange Rate	0.88

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities as follows:

(Cdn$ millions)	
WTI—US$1/bbl Change above US$50	73
WTI—US$1/bbl Change below US$50	42
NYMEX Natural Gas—US $1.00/mcf Change	66
Exchange Rate—$0.01 Change	35

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	2006	2005
Net Debt [1]		
Bank Debt	1,410	171
Public Senior Notes	2,885	2,980
Senior Debt	4,295	3,151
Subordinated Debt	536	536
Total Debt	4,831	3,687
Less: Cash and Cash Equivalents	(101)	(48)
Total Net Debt	**4,730**	**3,639**
Shareholders' Equity [2]	**4,636**	**3,996**

Notes:

1 *Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.*

2 *At January 31, 2007, there were 262,830,108 common shares and US$460 million of unsecured subordinated securities outstanding. These subordinated securities may be redeemed by issuing common shares at our option after November 8, 2008. The number of shares issuable depends on the common share price on the redemption date.*

Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows, capital investment activities and disposition programs. We ended the year with net debt of $4.7 billion, an increase of $1.1 billion from 2005. In 2006, we invested over $3.4 billion in capital projects, with more than 50% of this at Long Lake and Buzzard. These major projects did not contribute to cash flow in 2006 but will start to contribute in 2007 and beyond. We financed our 2006 capital program with cash flow from operating activities and borrowed US$925 million under our term credit facilities.

The year-over-year change in our net debt results from:

(Cdn$ millions)	2006	2005
Capital Investment	3,408	2,638
Cash Flow from Operating Activities	(2,374)	(2,143)
Excess of Capital Investment over Cash Flow	1,034	495
Net Proceeds on Disposition of Assets	(27)	(911)
Net Proceeds from Canexus Initial Public Offering	–	(301)
Dividends on Common Shares	52	52
Issue of Common Shares	(48)	(58)
Foreign Exchange Translation of US-dollar Debt and Cash	31	(113)
Other	49	190
Increase (Decrease) in Net Debt	**1,091**	**(646)**

The change in our net debt has increased our leverage levels as reflected in following ratios:

(times)	2006	2005	2004
Net Debt to Cash Flow from Operating Activities	2.0	1.7	2.7
Interest Coverage [1]	9.6	9.7	11.9

Note:

1 Earnings before interest, taxes, DD&A and exploration expense divided by interest expense (before capitalized interest).

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. We have leveraged our balance sheet in the past to accomplish our growth strategy, as most of our projects have long-cycle times, requiring significant amounts of capital to be invested prior to generating cash flows. Historically, we have been successful with this strategy as we used leverage to:

- develop the Masila project in Yemen in 1993;
- acquire Wascana in 1997;
- repurchase 20 million common shares in 2000;
- acquire the remaining interest in Aspen in 2003;
- acquire the Buzzard project and other key assets in the North Sea in 2004;
- build our first phase of Long Lake, scheduled to be on stream in late 2007; and
- fund remaining development capital.

Each time, we exceeded our internal net debt to cash flow target band; however, we successfully brought our leverage down through asset sales and incremental cash flows. In 2006, we again increased our leverage levels as a result of capital expenditures on our major development projects at Buzzard and Long Lake. In 2007, we anticipate reducing our net debt to cash flow from operating activities ratio using cash flows from our Buzzard operations, as well as our Long Lake project, expected to come on stream in 2007.

Change in Working Capital

(Cdn$ millions)	2006	2005	Increase/ (Decrease)
Cash and Cash Equivalents	101	48	53
Restricted Cash and Margin Deposits	197	70	127
Accounts Receivable	2,951	3,151	(200)
Inventories and Supplies	786	504	282
Future Income Tax Assets	479	–	479
Accounts Payable and Accrued Liabilities	(3,879)	(3,727)	(152)
Other	(1)	(17)	16
Total	**634**	**29**	**605**

Lower natural gas prices reduced our year end accruals for our marketing accounts receivable and accounts payable. This has been offset by higher prices in crude oil markets. We expanded our crude oil physical and financial trading activities to capture market gains. This expanded activity increased our marketing accounts receivable and accounts payable. We took advantage of lower natural gas prices and expanded our gas storage inventories by 27 bcf during the year. Volatile gas markets also increased the value of our derivative contract assets and liabilities.

Our accounts payable and accrued liabilities have increased since 2005 from higher accrued stock-based compensation obligations as a result of our strong share price, higher accruals related to our capital investment programs and our accrual related to the Block 51 settlement. We have reclassed $479 million of future income tax assets to current assets. This represents tax loss carry-forward balances in our UK operations that we expect to use in the next twelve months now that Buzzard is on stream.

Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. We build our opportunity portfolio to provide a balance of short-term, mid-term, and longer-term growth. Given the long cycle-time of some of our development projects and the volatility of commodity prices, it is not unusual in any given year for capital expenditures to exceed our cash flow. In addition, we require liquidity for our energy marketing business. Accordingly, we maintain significant committed credit facilities. At December 31, 2006, we had committed term credit facilities of $3.6 billion that are available until 2011. At year end, $1,078 million was drawn on these facilities and $294 million of these facilities were utilized to support letters of credit. We also had $632 million of uncommitted, unsecured credit facilities, of which $158 million was drawn at year end and $252 million was utilized to support letters of credit.

From time to time, we access the capital markets to meet our financing needs. We also use various financial instruments to minimize our exposure to fluctuations in commodity prices and foreign exchange. For example, we purchased WTI put options for 2007 to mitigate cash flow volatility. Overall, we manage our capital structure to maintain flexibility so we can fund our capital programs throughout the highs and lows of the price cycles inherent in the oil and gas business.

The following table shows how we finance our business activities. When our operating cash flows exceed our investment requirements, we generally pay down debt. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn$ millions)	2006	2005	2004	2003	2002
Cash Flow from Operating Activities	2,374	2,143	1,606	1,405	1,250
Cash Flow from Investing Activities	(3,388)	(1,864)	(4,013)	(1,219)	(1,569)
Surplus (Deficiency)	(1,014)	279	(2,407)	186	(319)
Cash Flow from Financing Activities	1,081	(274)	1,426	1,006	329
	67	**5**	**(981)**	**1,192**	**10**

In 2002, we began to invest significantly in two deep-water Gulf of Mexico projects (Aspen and Gunnison), our Syncrude expansion and our Long Lake project. We accessed public debt markets in 2002 to fund these investments. In 2003, Aspen contributed significantly to our cash flow and in late 2003, we pre-funded debt repayments by raising more than $1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher-cost debt, and coupled with acquisition credit facilities, acquired the North Sea assets. In 2005, we used our cash flow and the proceeds from asset dispositions to fund our capital program and repay debt. In 2006, we borrowed approximately $1 billion under our committed term credit facilities and used our cash flow from operating activities to fund our capital program.

Our marketing business also requires liquidity to support its asset-based trading strategy. We require liquidity for working capital, cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements typically require posting of collateral when adverse credit-related events occur, such as a reduction in credit ratings. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required in the event of reductions in our credit ratings.

Future Liquidity

Our future liquidity is primarily dependent on cash flows generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Assuming WTI of US$50/bbl, we expect our 2007 cash flow to exceed our capital investment program and dividend requirements by more than $300 million. In July 2007, we are required to repay $150 million of medium term notes that become due, however, we plan to fund this with our term credit facilities.

Our cash flow is sensitive to changes in commodity prices and exchange rates. For 2007, we expect cash flow of approximately $3.3 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US$/bbl)	50.00
NYMEX Natural Gas (US$/mmbtu)	6.00
US to Canadian Dollar Exchange Rate	0.88

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. The impact of a variance in any one of the above assumptions on our cash flow is described in the Outlook for 2007 section on page 64.

For 2007, we expect cash flow of approximately $3.3 billion.

We are in the midst of a number of development projects that require capital to bring them on stream. We anticipate that we will spend an additional $500 million in 2007 to bring the first phase of Long Lake on stream. In addition, we expect to spend $200 million in 2007 on furthering our coalbed methane projects in central Alberta and $235 million to complete the Ettrick development in the North Sea by mid 2008.

While these development projects lack exploration risk, they are subject to other risks including higher than anticipated capital costs or delayed start-up. We maintain undrawn committed credit facilities to manage this risk. In addition to our operating cash flows and our undrawn committed credit facilities, we have a US$1.5 billion shelf prospectus available in the US and Canada.

At December 31, 2006, the average term to maturity of our long-term debt was 16.6 years. We have the following short and long-term debt maturities during the next five years:

(Cdn$ millions)	2007	2008	2009	2010	2011
Uncommitted Credit Facilities	158	–	–	–	–
Term Credit Facilities [1]	–	–	–	–	1,078
Canexus LP Term Credit Facilities	–	–	–	174	–
Debentures	–	–	–	–	–
Medium Term Notes	150	125	–	–	–
Total	**308**	**125**	**–**	**174**	**1,078**

Note

1 $3.6 billion available until 2011

With our expected cash flow streams, commodity price and hedging strategies, current levels of liquidity, and access to debt and equity markets, we expect to be able to fund our planned capital programs, dividend requirements and debt repayments, or meet other obligations that may arise from our oil and gas, chemicals and marketing operations.

In 2006 we declared common share dividends of $0.20 per share (2005—$0.20, 2004—$0.20). We expect to declare common share dividends of $0.20 per share in 2007.

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

		Payments			
(Cdn$ millions)	**Total**	**<1 year**	**1-3 years**	**4-5 years**	**>5 years**
Short-Term and Long-Term Debt	4,831	308	125	1,252	3,146
Interest on Long-Term Debt	4,859	215	406	403	3,835
Operating Leases [1]	752	44	236	240	232
Capital Leases	119	5	10	10	94
Energy Commodity Contract Liabilities	524	325	191	8	–
Transportation and Storage Commitments [1]	927	424	262	123	118
Work Commitments and Purchase Obligations [2]	1,460	663	419	218	160
Asset Retirement Obligations	1,770	21	42	34	1,673
Total	**15,242**	**2,005**	**1,691**	**2,288**	**9,258**

Notes:

1 *Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.*

2 *Some of these payments relate to work commitments cancellable at our option without penalties or additional fees.*

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur.

- Short-term and long-term debt amounts are included on our December 31, 2006 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and our processing agreement that allows our Aspen production to flow through Shell's processing facilities at the Bullwinkle platform. The terms of the processing agreement give Shell an annual option to take payment in cash or in kind. For 2007, Shell has elected to take payment in kind, so the 2007 obligation has been excluded from this table. Instead, it is shown as a royalty and excluded from reserves and production.
- Capital leases include pipeline commitments primarily related to future production at Long Lake.
- Energy commodity contract liabilities include the purchase and sale of physical quantities of oil and natural gas, and financial derivatives used to manage our exposure to commodity prices. For contracts where the price is based on an index, the amount is based on forward market prices at December 31, 2006. For certain contracts, we may net settle.
- Work commitments include non-discretionary capital spending related to drilling, seismic, construction of facilities and other development commitments in our international operations, and includes Long Lake ($157 million) and the Ettrick development in the North Sea ($233 million). The timing of certain payments is difficult to determine with certainty. The table has been prepared using our best estimates; the remainder of our 2007 capital investment is discretionary.
- We also have included work commitments relating to drilling rigs, which have been contracted to work for us in the North Sea and Gulf of Mexico, totalling $414 million over the next five years.

- We have $1,770 million of undiscounted asset retirement obligations after inflation. As of December 31, 2006, the discounted value ($704 million) of these estimated obligations has been provided for in our Consolidated Financial Statements (including $21 million of current liabilities). The timing of any payments is difficult to determine with certainty, and the table has been prepared using our best estimates.
- We have unfunded obligations under our defined benefit pension plans of $122 million (Nexen—$67 million; Canexus—$8 million; Syncrude—$47 million). Our obligations for Nexen and Canexus include $54 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are indeterminable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and our expected capital expenditures for 2007.
- We have excluded our future income tax liabilities as the amount and timing of any cash payments for income taxes are based primarily on taxable income for each fiscal year in the various jurisdictions in which we operate.

From time to time, we enter into contracts that require us to indemnify parties against possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe these matters would not have a material adverse effect on our liquidity, financial condition or results of operations.

Credit Ratings

Currently, our senior debt is rated Baa2 by Moody's Investor Service, Inc. (Moody's), BBB by Dominion Bond Rating Service (DBRS) and BBB- by Standard & Poor's (S&P). In addition, Moody's and DBRS currently rate our outlook as stable while S&P has a positive outlook. Our strong financial results, ample liquidity and financial flexibility continue to support our credit ratings.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require posting of collateral when adverse credit-related events occur such as a reduction in credit ratings. Based on the contracts in place and commodity prices at December 31, 2006, we could be required to post collateral of up to $1,149 million if we were downgraded to non-investment grade. These obligations are already reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts owing to us if they are downgraded to non-investment grade.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees on page 69 and in Note 15 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference. At December 31, 2006, we had outstanding letters of credit amounting to $294 million and $252 million supported by our committed term credit facilities and our uncommitted credit facilities, respectively.

Contingencies

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 15 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect the reported amounts of our assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, derivative contract assets and liabilities and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

Oil and Gas Accounting—Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties.

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

Reserve estimates for each property are internally prepared at least annually by the property's reservoir engineer. They are reviewed by engineers familiar with the property and by divisional management. An Executive Reserves Committee, including our CEO, CFO and board-appointed internal qualified reserves evaluator, meet with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator assesses whether our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included in an exhibit to this Form 10-K.

Our reserves are based on internal estimates. To increase our confidence in our estimates, we have at least 80% of our oil and gas and Syncrude reserves assessed (i.e. either evaluated or audited) annually by independent qualified reserves consultants. Given that reserve estimates are based on numerous assumptions, interpretations and judgements, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio often differ by significantly more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest.

At December 31, 2006, we had 98% of our oil and gas and Syncrude reserves before royalties (98% after royalties) assessed by independent engineers. DeGolyer and MacNaughton performed evaluations of our proved reserves for each of the Masila Block (Yemen), Block 51 (Yemen), Usan (Nigeria) and our United Kingdom properties. McDaniel & Associates Consultants Ltd. (McDaniel) prepared one evaluation comprising a portion of our Canadian conventional, coalbed methane and Long Lake properties. An evaluation is a process whereby a qualified reserves evaluator prepares their estimate of the remaining quantities of oil and gas reserves by assessing and interpreting all available data on a reservoir to allow them to assess whether our estimates are reasonable. McDaniel performed an audit of our Syncrude interest. Ryder Scott Company audited a portion of our US Gulf of Mexico shelf properties. William M. Cobb & Associates, Inc. audited our US Gulf of Mexico deep-water properties. An audit is a process whereby an independent qualified reserves auditor reviews our estimates, supporting work papers and other data as they feel is necessary to prepare their estimate of remaining quantities of oil and gas reserves to allow them to assess whether our estimates are reasonable.

The board of directors has established a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent, and each being familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with each of the internal qualified reserves evaluator and independent reserves consultants, independent of management, to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

The Reserves Committee has reviewed Nexen's procedures for preparing the reserves estimates and related disclosures. It has reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result of this, the Reserves Committee is satisfied that the internally-estimated reserves are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the board has approved the reserves estimates and related disclosures in the Form 10-K.

Reserves estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2006, $169 million of our total $289 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by $120 million.
- Calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2006, oil and gas depletion of $741 million was recorded in depletion, depreciation, amortization and impairment expense. If our reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $74 million, assuming no other changes to our reserves profiles.
- Assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

Property, Plant and Equipment—Impairment

We evaluate our long-lived assets (oil and gas properties, Syncrude and chemicals) for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant negative revision to our reserves estimates, changes in operating and capital costs, or significant

or adverse political changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value. We assessed our oil and gas assets for impairment at the end of 2006 and recorded an impairment charge of $93 million, primarily related to two natural gas producing properties in the Gulf of Mexico.

Cash flow estimates for our impairment assessments require assumptions about two primary elements—future prices and reserves. Our estimates of future prices require significant judgements about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US$18/bbl to US$79/bbl and US$2/mmbtu to US$16/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows generally assume our long-term price forecast and forecast operating and development costs. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in these estimates would impact all except our chemicals and energy marketing businesses.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserves estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserves estimate decrease would have on our assessment of impairment.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future asset retirement obligations requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities, Syncrude assets and chemical plants. In arriving at amounts recorded, numerous assumptions and judgments are made with respect to ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations we have recorded result in an increase to the carrying cost of our property, plant and equipment. The obligations are accreted with the passage of time. A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our net income.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results.

Business Combination—Purchase Price Allocation

During the fourth quarter of 2004, we acquired a company operating and exploring oil and gas properties located in the North Sea. We accounted for this acquisition using the purchase method of accounting. Under this method, we were required to record on our Consolidated Balance Sheet the estimated fair values of the acquired company's assets and liabilities at the acquisition date. The excess of the purchase price over the fair values of the tangible and intangible net assets acquired was recorded as goodwill.

We made various assumptions in determining the fair values of the acquired company's assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimated (a) oil and gas reserves in accordance with our reserve standards, (b) additional reserves potential and (c) future prices of oil and gas.

Our reserve estimates were based on the work performed by our engineers and outside consultants. The judgments associated with these estimated reserves are described earlier in our critical accounting estimates discussion entitled "Oil and

Gas Accounting—Reserves Determination". Our estimates of future prices were based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. The judgments associated with these estimates are described earlier in our critical accounting estimates discussion entitled "Oil and Gas Accounting—Impairment".

We applied our estimated future prices to the estimated reserves quantities acquired, and we estimated future operating and development costs, to arrive at estimated future net revenues for the properties acquired. For proved properties, we discounted the future net revenues using after-tax discount rates. The same principles were applied in arriving at the fair value of unproved properties acquired. These unproved properties generally represent the value of the probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, an appropriate risk-weighting factor was applied to the discounted future net revenues of the probable and possible reserves in each particular instance.

If the fair value allocated to oil and gas properties acquired had been decreased by $50 million, future income tax liabilities would have decreased by $20 million and goodwill would have increased by $30 million.

Future Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and tax purposes. We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have made adequate provision for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In an effort to harmonize Canadian GAAP with US GAAP, the Canadian Accounting Standards Board (AcSB) has issued sections:

- 1530, *Comprehensive Income;*
- 3855, *Financial Instruments—Recognition and Measurement;* and
- 3865, *Hedges.*

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are held for trading or they are derivatives.

Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of "other comprehensive income". Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income, but are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, translation of self-sustaining foreign operations, and unrealized gains or losses on financial instruments available for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard.

These new standards are effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. Adoption of these standards as at December 31, 2006 would have the following impact on our Consolidated Financial Statements:

(Cdn$ millions)	Increase/ (Decrease)
Accounts Receivable	25
Future Income Tax Liabilities	7
Cumulative Foreign Currency Translation Adjustment	161
Accumulated Other Comprehensive Income	(143)

In March 2006, the CICA's Emerging Issues Committee (EIC) issued Abstract 160, *Stripping Costs Incurred in the Production Phase of a Mining Operation* (EIC-160). EIC-160 outlines accounting for overburden and mine waste materials removed in the process of accessing mineral deposits according to the benefit received by the entity. Generally, stripping costs should be accounted for as variable production costs and included in the costs of inventory produced in the period the stripping costs are incurred. If it can be shown that the stripping was for betterment of the mineral property, stripping costs should be capitalized. The standard outlines the requirement for amortization of capitalized stripping costs as well as a reconciliation of stripping costs incurred in the production phase. EIC-160 is effective for fiscal years beginning on or after July 1, 2006. We do not expect the adoption of EIC-160 will have any material impact on our results of operations or financial position.

In July 2006, the EIC issued Abstract 162, *Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date* (EIC-162). EIC-162 provides that if an employee is eligible to retire on the grant date of a stock-based award, related compensation expense is recognized in full at that date as there is no ongoing service requirement to earn the award. In addition, if the employee becomes eligible to retire during the vesting period, related compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. EIC-162 is effective for interim and annual periods ending on or after December 31, 2006. We adopted EIC-162 on a retroactive basis in the fourth quarter of 2006. For the year ended December 31, 2006, the impact of adopting EIC-162 decreased general and administrative expense by $9 million, increased provision for future income taxes by $3 million, increased net income $6 million, and increased basic and diluted earnings per share by $0.02/share. For the year ended December 31, 2005, the impact of adopting EIC-162 increased general and administrative expense by $17 million, decreased provision for future income taxes by $5 million, reduced net income by $12 million, and reduced basic and diluted earnings per share by $0.05/share. The impact on the year ended December 31, 2004 was immaterial.

In December 2006, the AcSB issued two new Sections in relation to financial instruments: Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*. Both sections will become effective for annual and interim periods beginning on or after October 1, 2007 and will require increased disclosure of financial instruments.

In December 2006, the AcSB issued Section 1535, *Capital Disclosures*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital. The standard is effective for annual periods beginning on or after October 1, 2007.

US Pronouncements

On January 1, 2006, we adopted FASB Statement 123 (revised), *Share-Based Payment* (Statement 123(R)) using the modified-prospective approach and graded-vesting amortization. Under Statement 123(R), our tandem options and stock appreciation rights are considered liability-based stock compensation plans. Under the modified-prospective approach, no amounts are restated in prior periods. Upon adoption of Statement 123(R), we recorded a cumulative effect of a change in accounting principle of $2 million. This amount was recorded in general and administrative expenses during the first quarter of 2006 in our US GAAP Consolidated Statement of Income.

Prior to the adoption of Statement 123(R), we accounted for our liability-based stock compensation plans in accordance with FASB Interpretation 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans* (the intrinsic-value method). Accordingly, obligations were accrued on a graded-vesting basis and represented the difference between the market value of our common shares and the exercise price of underlying options and rights. Under Statement 123(R), obligations for liability-based stock compensation plans are measured at their fair value, and are re-measured at fair value in each subsequent reporting period.

Consistent with Statement 123(R), we account for any stock options that do not include a cash feature (equity-based stock compensation plans), using the fair-value method.

The impact of adopting Statement 123(R) on our results for the year ended December 31, 2006 is as follows:

(Cdn$ millions, except per share amounts)	Prior to Adoption of FAS 123(R)	After Adoption of FAS 123(R)	Increase/ (Decrease)
Income from Continuing Operations before Income Taxes—US GAAP	1,306	1,264	(42)
Net Income—US GAAP	608	579	(29)
Basic Earnings per Common Share—US GAAP ($/share)	2.32	2.21	(0.11)
Diluted Earnings per Common Share—US GAAP ($/share)	2.26	2.15	(0.11)

We recognize stock-based compensation expense for our retired and retirement-eligible employees over an accelerated graded vesting period in accordance with the provisions of Statement 123(R) for stock-based awards granted to employees after December 31, 2005. For stock-based awards granted prior to the adoption of Statement 123(R), stock-based compensation expense for our retired and retirement-eligible employees is recognized over a graded vesting period. If we applied the accelerated vesting provisions of Statement 123(R) to stock-based awards granted to our retired and retirement-eligible employees prior to the adoption of Statement 123(R), there would be no material change to our stock-based compensation expense for the three years ended December 31, 2006.

In February 2006, the FASB issued Statement 155, *Accounting for Certain Hybrid Instruments*, which amends Statement 133, *Accounting for Derivative Instruments and Hedging Activities*, and Statement 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. Statement 155 permits fair value re-measurement of hybrid financial instruments that contain an embedded derivative that otherwise would require bifurcation from its host contract in accordance with Statement 133. Statement 155 also clarifies and amends certain other provisions of Statement 133 and Statement 140. This statement is effective for all financial instruments acquired or issued in fiscal years beginning after September 15, 2006. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In July 2006, FASB issued FIN 48 *Accounting for Uncertainty in Income Taxes* with respect to FAS 109 *Accounting for Income Taxes* regarding accounting for and disclosure of uncertain tax positions. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes and is effective for fiscal years beginning after December 15, 2006. Adoption of this standard is expected to increase our future income tax liabilities by no more than $30 million and decrease our retained earnings by a corresponding amount.

In September 2006, FASB issued Statement 157, *Fair Value Measurements*. Statement 157 defines fair value, establishes a framework for measuring fair value under US generally accepted accounting principles and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In September 2006, FASB issued Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. Statement 158 requires an employer to recognize the over-funded or under-funded status of a defined benefit post-retirement plan on the balance sheet as an asset or liability and to recognize changes in funded status through comprehensive income. This statement also requires measurement of the funded status of a plan as of the balance sheet date. The recognition and disclosures under Statement 158 are required for fiscal years ending after December 15, 2006 while the new measurement date is effective for fiscal years ending after December 15, 2008. We adopted the recognition and disclosure provisions at December 31, 2006 in our US GAAP presentation. We do not expect the adoption of the change in measurement date in 2008 to have a material impact on our results of operations or financial position.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to normal market risks inherent in the oil and gas, Syncrude, energy marketing and chemicals businesses, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

NON-TRADING

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are commodities which are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for oil and gas exploration and development.

Our crude oil prices are based on various reference prices, primarily the WTI crude oil reference price and other prices which generally track the movement in WTI. Adjustments are made to the reference prices to reflect quality differentials and transportation. WTI and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and North American supply and demand, and to a lesser extent local market conditions.

In 2006, WTI averaged US$66.22/bbl reaching a high of US$78.40/bbl and a low of US$54.86/bbl. NYMEX natural gas prices averaged US$6.99/mmbtu in 2006, reaching a high of US$11.00/mmbtu and a low of US$4.05/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2007 cash flow from operating activities and net income are as follows:

(Cdn$ millions)	Cash Flow	Net Income
WTI—US$1/bbl Change above US$50	73	46
WTI—US$1/bbl Change below US$50	42	26
NYMEX Natural Gas—US$1.00/mcf Change	66	56

These sensitivities to changes in benchmark prices for crude oil and natural gas are based on our estimated 2007 production levels for crude oil and natural gas and assume a Canadian/US dollar exchange rate of $0.88. Our estimated crude oil and natural gas production range for 2007 is between 275,000 and 305,000 boe/d before royalties, of which natural gas represents approximately 18%.

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In 2006, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2007, by establishing an annual average WTI floor price of US$50/bbl on 105,000 bbls/d of production.

Foreign Currency Risk

A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations; and
- short-term and long-term borrowings.

The Canadian/US dollar exchange rate averaged $0.88 in 2006 with a high of $0.91 and a low of $0.85.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2007 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

(Cdn$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-Term Debt
$0.01 Change in US to Canadian Dollar	35	12	19	31

Our sensitivities to changes in the Canadian/US dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar denominated long-term debt for 2007. These estimates are based on a WTI price for crude oil of US$50/bbl, a NYMEX natural gas price of US$6/mmbtu, operating costs of $8/boe and a Canadian/US dollar exchange rate of $0.88.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in foreign operations.

Our chemicals operations are exposed to changes in the US-dollar exchange rate as a portion of their sales are denominated in US-dollars. Canexus periodically purchases US-dollar call options to reduce this exposure. Under outstanding option contracts at December 31, 2006, Canexus had the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.85 to January 10, 2007 and has the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.87 for the period January 10, 2007 to July 11, 2007.

We do not have any material exposure to highly inflationary foreign currencies.

Interest Rate Risk

We are exposed to fluctuations in interest rates on our floating-rate debt. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2007 cash flow from operating activities and net income is as follows:

(Cdn$ millions)	Cash Flow	Net Income
Interest Rates—1% change in rates	9	6

Our sensitivity to changes in interest rates is based on 2007 estimated average floating rate debt of $900 million and a Canadian/US dollar exchange rate of $0.88.

Our floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2006, fixed-rate borrowings comprised 73% (2005—95%) of our long-term debt at an effective average rate of 6.3% (2005—6.3%). During the year, we periodically drew on our committed, unsecured, term credit facilities and at December 31, 2006, floating-rate debt comprised 27% (2005—5%) of our long-term debt at an effective average rate of 5.7% (2005—4.4%) reaching a high of 6.4% and a low of 4.25% during 2006.

We had no interest rate swaps outstanding in 2006 or 2005.

TRADING

Commodity Price Risk

Our marketing operation is involved in the marketing and trading of crude oil, natural gas, natural gas liquids and power through the use of physical purchase and sales contracts, as well as financial commodity contracts. These activities expose us to commodity price risk, as well as foreign currency risk and volatility within these markets. The marketing group actively manages this risk by utilizing energy-related futures, forwards, swaps and options, as well as currency swaps or forwards. The marketing operation also tries to take advantage of volatility within commodity markets and can establish net open commodity positions to take advantage of existing market conditions.

Volatility within our various markets can vary and changes over time. While this volatility gives us opportunities, it can also cause our results to vary significantly between periods. We attempt to manage associated risk and take on positions based on solid market intelligence, however, it is possible that we could incur financial loss.

Open positions exist where not all contracted purchases and sales terms have been matched. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk sensitivities in our portfolio). Open positions and derivative instruments expose us to other risks, including credit risk and liquidity risk. The inability to close out options, futures and forward positions could have an adverse impact on our ability to use derivative instruments to effectively hedge our portfolio and/or generate income from trading activities.

We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss, given a 95% confidence level, that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" (for natural gas since May 2006) distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. In May 2006, the methodology for estimating the input parameters for the VaR calculation for natural gas was revised to improve performance and stability under a range of normal and low probability market conditions. The new methodology produces VaR results substantially similar to the prior method with no material changes.

Stress testing complements our VaR estimate. It is used to quantify potential unexpected losses from low probability market movements. Credit VaR is reported separately from commodity VaR, and ranged between $4 and $5 million in 2006.

Our year end, annual high, annual low and annual average VaR amounts are as follows:

(Cdn$ millions)	2006	2005	2004
Value at Risk			
Year End	26	24	21
High	33	28	42
Low	17	11	17
Average	23	21	29

Our board of directors has approved formal risk management policies for our energy trading activities. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the board of directors and our Risk Management Committee monitor our exposure to the above risks and review the results of our energy trading activities regularly.

CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including energy traders, and are subject to normal industry credit risk. We take the following measures to reduce this risk:

- we assess the financial strength of our counterparties through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- we routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the board;
- we set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2006:

- over 98% of our credit exposures were investment grade; and
- only 2 counterparties individually made up more than 5% of our credit exposure. Both were investment grade.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations*, are forward-looking statements [1]. Forward-looking statements are generally identifiable by terms such as *anticipate, believe, intend, plan, expect, estimate, budget, outlook* or other similar words, and include statements relating to future production associated with our Coalbed Methane, Long Lake, and West Africa projects and future capital investment plans.

These statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. These risks, uncertainties and other factors include, among others:

- market prices for oil, natural gas and chemicals products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- volatility in energy trading markets;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions that increase taxes or royalties, change environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigations, arbitration or regulatory proceedings; and
- political uncertainty, including actions by insurgent or other armed groups or other conflict, including conflict between states.

The above items and their possible impact are discussed more fully in the section, titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures about Market Risk* in Item 7A.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and management's future course of action depends upon our assessment of all information available at that time. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future asset dispositions;
- future sources of funding for our capital program;
- possible commerciality, development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come on stream.

We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. Except to the extent required by law, we undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

Note:

1 *Within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended.*

SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In 2003, Canadian regulatory authorities adopted *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribes that Canadian companies follow

certain standards for the preparation and disclosure of reserves and related information. We have been granted the following exemptions permitting us to:

- substitute our SEC disclosures for much of the annual disclosure required by NI 51-101;
- prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) modified to reflect SEC requirements;
- dispense with the requirement to have our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, evaluated or audited by independent qualified reserves evaluators; and
- not disclose certain prescribed information pertaining to prospects if such disclosures would result in the contravention of a legal obligation, would likely be detrimental to our competitive interests or the information does not exist.

As a result of these exemptions, Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein* calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved developed reserves by geographic region only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not prescribe the nature of the information required in connection with proved undeveloped reserves and future development costs whereas NI 51-101 requires certain detailed information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions whereas NI 51-101 requires that various F&D costs per boe be disclosed. NI 51-101 requires that F&D costs be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year;
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports;
- the SEC does not consider the upgrading component of our integrated oil sands project at Long Lake as an oil and gas activity, and therefore permits recognition of bitumen reserves only. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits recognition of synthetic reserves. At year end, we have recognized 246 million barrels before royalties of proved bitumen reserves (219 million barrels after royalties) under SEC requirements, whereas under NI 51-101 we would have recognized 200 million barrels before royalties of proved synthetic reserves (185 million barrels after royalties); and
- the SEC considers our Syncrude operation as a mining activity rather than an oil and gas activity, and therefore does not permit related reserves to be included with oil and gas reserves. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits them to be included with oil and gas reserves. We have provided a separate table showing our share of the Syncrude proved reserves as well as the additional disclosures relating to mining activities required by SEC requirements.

The foregoing is a general description of the principal differences only.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Financial Statements

Strong commodity prices and record results from our marketing group resulted in solid financial results for 2006. Cash flow from operating activities was a record $2.4 billion, while net income was $601 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF MANAGEMENT

February 9, 2007

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and fair presentation of the consolidated financial statements, as well as the financial reporting process that gives rise to such consolidated financial statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for the development and implementation of internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company, and that our records are reliable for preparing our consolidated financial statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our board of directors is responsible for reviewing and approving the consolidated financial statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors and includes four directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws), pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with or without the presence of management.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the accompanying consolidated balance sheets of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2006 and 2005 and the consolidated statements of income, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Nexen Inc. and subsidiaries as of December 31, 2006 and 2005 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 9, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Calgary, Canada
February 9, 2007

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the change described in Note 1(u) to the consolidated financial statements. Our report to the board of directors and shareholders on the consolidated financial statements of the Company dated February 9, 2007, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Calgary, Canada
February 9, 2007

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

NEXEN INC.

CONSOLIDATED STATEMENT OF INCOME

FOR THE THREE YEARS ENDED DECEMBER 31, 2006

Cdn$ millions, except per share amounts	2006	2005	2004
		Note 1(u)	Note 1(u)
Revenues and Other Income			
Net Sales	3,936	3,932	2,944
Marketing and Other (Note 17)	1,450	702	713
Gain on Dilution of Interest in Chemicals Business (Note 2)	–	193	–
	5,386	4,827	3,657
Expenses			
Operating	955	893	722
Depreciation, Depletion, Amortization and Impairment (Note 6)	1,124	1,052	674
Transportation and Other	1,041	796	549
General and Administrative	555	809	299
Exploration	362	250	243
Interest (Note 8)	53	97	143
	4,090	3,897	2,630
Income from Continuing Operations before Income Taxes	1,296	930	1,027
Provision for Income Taxes (Note 18)			
Current	368	339	248
Future	315	(105)	69
	683	234	317
Net Income from Continuing Operations before Non-Controlling Interests	613	696	710
Net Income Attributable to Non-Controlling Interests	12	8	–
Net Income from Continuing Operations	601	688	710
Net Income from Discontinued Operations (Note 14)	–	452	83
Net Income	**601**	**1,140**	**793**
Earnings Per Common Share from Continuing Operations ($/share)			
Basic (Note 13)	2.29	2.64	2.76
Diluted (Note 13)	2.24	2.58	2.72
Earnings Per Common Share ($/share)			
Basic (Note 13)	2.29	4.38	3.08
Diluted (Note 13)	2.24	4.28	3.04

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

CONSOLIDATED BALANCE SHEET

DECEMBER 31, 2006 AND 2005

Cdn$ millions, except share amounts	2006	2005
		Note 1(u)
ASSETS		
Current Assets		
Cash and Cash Equivalents	101	48
Restricted Cash and Margin Deposits	197	70
Accounts Receivable (Note 4)	2,951	3,151
Inventories and Supplies (Note 5)	786	504
Future Income Tax Assets (Note 18)	479	–
Other	67	51
Total Current Assets	4,581	3,824
Property, Plant and Equipment (Note 6)	11,739	9,594
Goodwill	377	364
Future Income Tax Assets (Note 18)	141	410
Deferred Charges and Other Assets (Note 10)	318	398
TOTAL ASSETS	**17,156**	**14,590**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings (Note 8)	158	–
Accounts Payable and Accrued Liabilities	3,879	3,727
Accrued Interest Payable	55	55
Dividends Payable	13	13
Total Current Liabilities	4,105	3,795
Long-Term Debt (Note 8)	4,673	3,687
Future Income Tax Liabilities (Note 18)	2,468	1,955
Asset Retirement Obligations (Note 9)	683	590
Deferred Credits and Other Liabilities (Note 11)	516	479
Non-Controlling Interests (Note 2)	75	88
Shareholders' Equity (Note 12)		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2006—262,513,206 shares		
2005—261,140,571 shares	821	732
Contributed Surplus	4	2
Retained Earnings	3,972	3,423
Cumulative Foreign Currency Translation Adjustment	(161)	(161)
Total Shareholders' Equity	4,636	3,996
Commitments, Contingencies and Guarantees (Notes 15 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**17,156**	**14,590**

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Charles W. Fischer"
Director

(signed) "Thomas C. O'Neill"
Director

NEXEN INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE THREE YEARS ENDED DECEMBER 31, 2006

Cdn$ millions	2006	2005	2004
		Note 1(u)	Note 1(u)
Operating Activities			
Net Income from Continuing Operations	601	688	710
Net Income from Discontinued Operations	–	452	83
Charges and Credits to Income not Involving Cash (Note 19)	1,629	1,081	906
Exploration Expense	362	250	243
Changes in Non-Cash Working Capital (Note 19)	(177)	(195)	(122)
Other	(41)	(133)	(214)
	2,374	2,143	1,606
Financing Activities			
Proceeds from Long-Term Notes and Debentures (Note 8)	–	1,253	1,779
Repayment of Long-Term Notes and Debentures (Note 8)	(93)	(1,818)	(300)
Proceeds from (Repayment of) Term Credit Facilities, Net	1,044	(66)	83
Proceeds from (Repayment of) Short-Term Borrowings, Net	160	(99)	101
Redemption of Preferred Securities	–	–	(289)
Dividends on Common Shares	(52)	(52)	(52)
Issue of Common Shares and Exercise of Options for Shares	48	58	124
Net Proceeds from Canexus Initial Public Offering (Note 2)	–	301	–
Proceeds from Term Credit Facilities of Canexus, Net (Notes 2 and 8)	2	176	–
Other	(28)	(27)	(20)
	1,081	(274)	1,426
Investing Activities			
Business Acquisitions, Net of Cash Acquired (Note 3)	(78)	–	(2,583)
Capital Expenditures			
Exploration and Development	(3,198)	(2,564)	(1,582)
Proved Property Acquisitions	(13)	(20)	(4)
Chemicals, Corporate and Other	(119)	(54)	(95)
Proceeds on Disposition of Assets	27	911	34
Changes in Non-Cash Working Capital (Note 19)	134	(54)	244
Changes in Restricted Cash and Margin Deposits	(127)	(70)	–
Other	(14)	(13)	(27)
	(3,388)	(1,864)	(4,013)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(14)	(30)	(33)
Increase (Decrease) in Cash and Cash Equivalents	53	(25)	(1,014)
Cash and Cash Equivalents—Beginning of Year	48	73	1,087
Cash and Cash Equivalents—End of Year	**101**	**48**	**73**

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

FOR THE THREE YEARS ENDED DECEMBER 31, 2006

Cdn$ millions	2006	2005	2004
		Note 1(u)	Note 1(u)
Common Shares (Note 12)			
Balance at Beginning of Year	732	637	513
Issue of Common Shares	32	29	31
Proceeds from Options Exercised for Shares	16	29	93
Accrued Liability Relating to Options Exercised	41	37	–
Balance at End of Year	**821**	**732**	**637**
Contributed Surplus			
Balance at Beginning of Year	2	–	1
Stock-Based Compensation Expense (Note 12)	2	2	2
Modification of Stock Option Plan to Tandem Option Plan (Note 12)	–	–	(3)
Balance at End of Year	**4**	**2**	**–**
Retained Earnings			
Balance at Beginning of Year	3,423	2,335	1,594
Net Income	601	1,140	793
Dividends on Common Shares	(52)	(52)	(52)
Balance at End of Year	**3,972**	**3,423**	**2,335**
Cumulative Foreign Currency Translation Adjustment			
Balance at Beginning of Year	(161)	(105)	(33)
Translation Adjustment, Net of Income Taxes	–	(56)	(72)
Balance at End of Year	**(161)**	**(161)**	**(105)**

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cdn$ millions, except as noted

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 21.

(a) Use of estimates

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, derivative contract assets and liabilities and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(b) Principles of consolidation

The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus LP (see Note 2) and its subsidiaries, are wholly owned and intercompany accounts and transactions have been eliminated. On August 18, 2005, we sold our chemicals operations to Canexus LP, but retained control of these operations through our 61.4% interest in Canexus LP. All of the assets, liabilities and results of operations of Canexus LP and its subsidiaries have been included in our consolidated financial statements. The non-Nexen ownership interests in Canexus LP and its subsidiaries are shown as non-controlling interests. We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. We also proportionately consolidate our 7.23% undivided interest in the Syncrude joint venture, which is considered a mining activity under US regulations. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities, the significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(c) Accounts receivable

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(j)). Our allowance for doubtful accounts provides for specific doubtful receivables.

(d) Inventories and supplies

Inventories and supplies for our oil and gas, marketing and chemicals operations are stated at the lower of cost and net realizable value. Cost is determined on the first-in, first-out method or average basis. Inventory costs include expenditures and other costs, including depreciation, depletion and amortization, directly or indirectly incurred in bringing the inventory to its existing condition.

(e) Property, plant and equipment (PP&E)

Property, plant and equipment is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We follow successful efforts accounting for our oil and gas business. All property acquisition costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the acquisition costs are reclassified to proved property

acquisition costs. Exploration drilling costs are capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized when a well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made to assess the reserves and the economic and operating viability of the well. All other exploration costs, including geological and geophysical and annual lease rentals, are expensed to earnings as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

PP&E for our Syncrude operation is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established, and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

(f) Depreciation, depletion, amortization and impairment (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs over remaining proved reserves. Depletion is considered a cost of inventory when the oil and gas is produced. When this inventory is sold, the depletion is charged to DD&A expense.

Our Syncrude PP&E is depleted using the unit-of-production method. Capitalized costs are depleted over proved and probable reserves within developed areas of interest.

We depreciate other plant and equipment costs, including our chemicals facilities, using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur that indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. These events or conditions occur periodically. If carrying value exceeds the sum of undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated total future cash flows, discounted for the time value of money, and we expense the excess carrying value to depreciation, depletion, amortization and impairment. Our cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(g) Carried interest

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(h) Asset retirement obligations

We provide for future asset retirement obligations on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The asset retirement obligation accretes until the time the retirement obligation is expected to settle, while the asset retirement cost is amortized over the useful life of the underlying PP&E. We periodically review our estimates for changes in expected amounts or timing of cash flows.

The amortization of the asset retirement cost and the accretion of the asset retirement obligation are included in depreciation, depletion, amortization and impairment. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the period of settlement.

(i) Goodwill

Goodwill is recorded at cost and is not amortized. We test goodwill for impairment annually based on estimated future cash flows of the reporting unit to which the goodwill is attributable. In addition, we test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount. If our goodwill is impaired, we write it down to its implied fair value, based on the fair value of the assets and liabilities of the underlying reporting unit. Our goodwill is attributable to our marketing and UK reporting units.

(j) Revenue recognition

Crude Oil and Natural Gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada, the US and the UK, our customers primarily take title when the crude oil and natural gas reaches the end of the pipeline. For our other international operations, our customers take title when the crude oil is loaded onto the tanker. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty payments to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty payments. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(g).

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery only takes place when we have a sales contract in place specifying delivery volumes and sales prices. We assess customer credit worthiness before entering into sales contracts to minimize collection risk.

Marketing

Substantially all of the physical purchase and sales contracts entered into by our marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our marketing operation are stated at fair value on the balance sheet unless the requirements for hedge accounting are met (see Note 1(n)). We record any change in fair value as a gain or loss in marketing and other.

Any margin realized by our marketing operation on the sale of our proprietary oil and gas production is included in marketing and other. Sales of our proprietary production are recorded at monthly market-based prices and intercompany profits and losses between segments are eliminated. We assess customer credit worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have the legal right of offset.

(k) Income taxes

We follow the liability method of accounting for income taxes (see Note 18). This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(l) Foreign currency translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using average exchange rates throughout the year.

Gains and losses resulting from this translation are included in the cumulative foreign currency translation adjustment in shareholders' equity. Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation, except on our designated US-dollar debt, are included in income. We have designated our US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other in the Consolidated Statement of Income.

(m) Capitalized interest

We capitalize interest on major development projects until the project is substantially complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(n) Derivative instruments

Non-Trading Activities

We use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Note 7). We record these instruments at fair value at the balance sheet date and record any change in fair value as a net gain or loss in marketing and other during the period of change unless the requirements for hedge accounting are met. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. We recognize gains and losses on the derivative instruments designated as hedges in the same period as the gains or losses on the hedged items are recognized. If effective correlation ceases, hedge accounting is terminated, and future changes in the market value of the derivative instrument are included as gains or losses in marketing and other in the period of change.

Trading Activities

Our marketing operation uses derivative instruments for marketing and trading crude oil and natural gas including:

- commodity contracts settled with physical delivery;
- exchange-traded futures and options; and
- non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other during the period of change. The fair value of these instruments is recorded as accounts receivable or

payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months, we record them as deferred charges and other assets or deferred credits and other liabilities.

(o) Employee future benefits

The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. We measure the plan assets and the accrued benefit obligation on October 31 each year.

(p) Stock-based compensation

In 2003, we adopted the fair-value method of accounting for stock options granted to employees and directors. We recorded stock-based compensation expense in the Consolidated Statement of Income as general and administrative expenses for all options granted on or after January 1, 2003, with a corresponding increase to contributed surplus. Compensation expense for options granted was based on estimated fair values at the time of grant and we recognized the expense over the vesting period of the option.

In May 2004, we modified our stock option plan to a tandem option plan by including a cash feature. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price. As a result of the modification, we record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the recorded liability amount is transferred to share capital.

Stock options awarded to our US employees between December 1, 2004 and December 1, 2005 do not include a cash feature and are not accounted for as tandem options. Instead, we account for these options using the fair-value method. Compensation expense is based on estimated fair values at the time of grant and is recognized over the vesting period of the options. The expense is included as general and administrative expense with a corresponding increase to contributed surplus. Stock options awarded to our US employees after December 1, 2005 are accounted for as tandem options.

We provide stock appreciation rights to employees as described in Note 12, and we account for these on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

(q) Cash and cash equivalents

Cash and cash equivalents include short-term, highly liquid investments that mature within three months of their purchase. They are recorded at cost, which approximates market value.

(r) Restricted cash and margin deposits

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts and other cash balances subject to regulatory restrictions.

(s) Leases

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases and the related assets are included with PP&E. These assets are depreciated on the same basis as other PP&E. Rental payments under operating leases are expensed as incurred.

(t) Transportation

We pay to transport the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as a cost to us and is recorded as transportation and other. Our marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments have been recorded as deferred liabilities and are recognized in net income as the transportation is used.

(u) Changes in accounting principles

Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date

In the fourth quarter of 2006, we retroactively adopted EIC-162, *Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date* (EIC-162). EIC-162 provides that if an employee is eligible to retire on the grant date of a stock-based award, related compensation expense is recognized in full at that date as there is no ongoing service requirement to earn the award. In addition, if an employee becomes eligible to retire during the vesting period, related compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. Prior to the adoption of EIC-162, we did not consider the retirement dates of our employees in the determination of our stock-based compensation expense. EIC-162 is effective for interim and annual periods ending on or after December 31, 2006 and is to be adopted on a retroactive basis. For the year ended December 31, 2006, the impact of adopting EIC-162 decreased general and administrative expense by $9 million, increased provision for future income taxes by $3 million, increased net income by $6 million, and increased basic and diluted earnings per share by $0.02/share. For the year ended December 31, 2005, the impact of adopting EIC-162 increased general and administrative expense by $17 million, decreased provision for future income taxes by $5 million, reduced net income by $12 million, and reduced basic and diluted earnings per share by $0.05/share. The impact on the year ended December 31, 2004 was immaterial.

2. CANEXUS INCOME FUND

In June 2005, our board of directors approved a plan to monetize our chemicals operations through the creation of an income trust and the issuance of trust units in an initial public offering. This initial public offering closed on August 18, 2005, with Canexus Income Fund (Canexus) issuing 30 million units at a price of $10 per unit for gross proceeds of $300 million ($284 million, net of underwriters' commissions).

Concurrent with the closing of the offering, Canexus acquired a 36.5% interest in Canexus Limited Partnership (Canexus LP) using the net proceeds from the initial public offering. Canexus LP acquired Nexen's chemicals business for approximately $1 billion, comprised of the net proceeds from Canexus' initial public offering and $200 million (US$167 million) of bank debt, plus the issuance of 52.3 million exchangeable limited partnership units (Exchangeable LP Units) of Canexus LP. At that time, the Exchangeable LP Units held by Nexen represented a 63.5% interest in Canexus LP.

The Exchangeable LP Units held by Nexen are exchangeable on a one-for-one basis for trust units of Canexus. As a result, the Exchangeable LP Units owned by Nexen were exchangeable into 52.3 million trust units which represented 63.5% of the outstanding trust units of Canexus assuming exchange of the Exchangeable LP Units.

On September 16, 2005, the underwriters of the initial public offering exercised a portion of their over-allotment option to purchase 1.75 million trust units at $10 per unit for gross proceeds of $18 million ($17 million, net of underwriters' commissions). As a result, Nexen exchanged 1.75 million of its Exchangeable LP Units for $17 million in net proceeds. After this exchange, Nexen has a 61.4% interest in Canexus LP represented by 50.5 million Exchangeable LP Units. The initial public offering, together with the exercise of the over-allotment, resulted in total net proceeds to Nexen of $301 million.

These transactions diluted our interest in our chemicals operations. As a result of this dilution, we recorded a gain of $193 million during the third quarter of 2005.

We have the right to nominate a majority of the members of the board of Canexus Limited, the corporation with responsibility for the strategic management and operational decisions of Canexus and Canexus LP. Nexen currently has nominated two representatives to the 10-member board of Canexus Limited. Since we have retained effective control of our chemicals business, the

results, assets and liabilities of this business have been included in these financial statements. The non-Nexen ownership interests in our chemicals business are shown as non-controlling interests.

During the year $28 million (2005 - $10 million) of distributions were paid to non-Nexen ownership interests.

3. BUSINESS ACQUISITIONS

In 2006, we completed minor business acquisitions related to our marketing group for $78 million, net of cash acquired. These acquisitions were accounted for using the purchase method of accounting. The assets and liabilities purchased were primarily working capital and we recorded goodwill of $12 million as a result of the acquisitions.

On December 1, 2004, we acquired 100% of the issued and outstanding share capital of EnCana (UK) Limited (EnCana UK) from EnCana Corporation (EnCana) for cash consideration of US$2.1 billion, subject to certain adjustments. EnCana UK held all of EnCana's offshore oil and gas assets in the North Sea. We acquired EnCana UK to establish a strategic presence in the North Sea by acquiring operatorship of the Buzzard field development and operatorship of the producing Scott and Telford fields. The acquisition also gave us access to interests in several satellite discoveries and more than 700,000 net undeveloped exploration acres. In addition, we acquired the management and technical teams that found and are developing the Buzzard discovery. Goodwill paid was attributable to the established North Sea presence acquired and the knowledge and business relationships acquired through the management team and employees of EnCana UK.

The acquisition has been accounted for using the purchase method, and the results of EnCana UK have been consolidated with the results of Nexen from December 1, 2004. The following table shows the allocation of the purchase price based on the estimated fair values of the assets and liabilities acquired:

Purchase Price, Net of Cash Acquired:	
Cash Paid	2,561
Transaction Costs	22
Total Purchase Price	**2,583**
Purchase Price Allocated as follows:	
Accounts Receivable	310
Inventories and Supplies	11
Other Current Assets	2
Property, Plant and Equipment	3,395
Future Income Tax Assets	239
Goodwill [1]	334
Deferred Charges and Other Assets	12
Accounts Payable and Accrued Liabilities	(289)
Asset Retirement Obligations	(134)
Future Income Tax Liabilities	(1,284)
Deferred Credits and Other Liabilities	(13)
Total Purchase Price Allocated	**2,583**

Note:
1 *The amount of goodwill deductible for tax purposes is nil.*

The unaudited pro forma results for the year ended December 31, 2004 are shown below as if the acquisition had occurred on January 1, 2004. Pro forma results are not necessarily indicative of actual results or future performance.

	2004
Revenues	4,258
Net Income	841
Earnings Per Common Share—Basic ($/share)	3.27
Earnings Per Common Share—Diluted ($/share)	3.23

4. ACCOUNTS RECEIVABLE

	2006	2005
Trade		
Marketing	2,226	2,400
Oil and Gas	600	614
Chemicals and Other	58	48
	2,884	3,062
Non-Trade	80	96
	2,964	3,158
Allowance for Doubtful Receivables	(13)	(7)
Total Accounts Receivable	**2,951**	**3,151**

5. INVENTORIES AND SUPPLIES

	2006	2005
Finished Products		
Marketing	609	320
Oil and Gas	21	11
Chemicals and Other	14	15
	644	346
Work in Process	5	6
Field Supplies	137	152
Total Inventories and Supplies	**786**	**504**

6. PROPERTY, PLANT AND EQUIPMENT

	2006			2005		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	779	599	180	833	546	287
Yemen—Carried Interest	1,625	1,529	96	1,410	1,295	115
Canada	5,216	1,448	3,768	3,631	1,311	2,320
United States	2,889	1,445	1,444	2,437	1,159	1,278
United Kingdom	4,710	432	4,278	4,013	216	3,797
Other Countries	249	78	171	249	119	130
	15,468	5,531	9,937	12,573	4,646	7,927
Marketing	226	47	179	177	72	105
Syncrude	1,304	179	1,125	1,240	171	1,069
Chemicals	854	494	360	827	456	371
Corporate and Other	286	148	138	245	123	122
Total PP&E	**18,138**	**6,399**	**11,739**	**15,062**	**5,468**	**9,594**

The above table includes capitalized costs of $6,708 million (2005—$5,211 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized. These costs include $2,399 million related to our Buzzard project in the North Sea that began operations in January 2007.

Our Syncrude operations are considered a mining operation for US reporting purposes. PP&E at December 31, 2006 and 2005 includes mineral rights of $6 million.

Depreciation, Depletion, Amortization and Impairment (DD&A)

Our 2006 DD&A expense includes $93 million of impairment expense, primarily related to two natural gas producing properties in the Gulf of Mexico. The impairment was caused by unsuccessful development programs and negative year-end reserve revisions. The carrying values of the impaired properties have been reduced to their estimated fair value. In addition, our 2006 DD&A expense includes $15 million (2005 - $58 million) relating to the write down of a portion of our purchase price allocation to unproved properties purchased in the North Sea as a result of unsuccessful exploration activities.

Research and Development

We incurred $53 million (2005—$54 million) in connection with research and development activities related to developing new technologies for increasing oil recoveries. Research costs of $50 million (2005—$44 million) were included in other expense on the Consolidated Statement of Income. The development costs have been deferred and are included in PP&E.

	2006	2005
Development Costs Deferred, Beginning of Year	25	15
Deferred in the Year	3	10
Amortized in the Year	–	–
Development Costs Deferred, End of Year	**28**	**25**

Suspended Well Costs

The following table shows the changes in capitalized exploratory well costs during the years ended December 31, 2006 and 2005, and does not include amounts that were initially capitalized and subsequently expensed in the same period.

	2006	2005
Balance at Beginning of Year	252	116
Additions to Capitalized Exploratory Well Costs Pending the Determination of Proved Reserves	129	174
Capitalized Exploratory Well Costs Charged to Expense	(70)	(27)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(84)	(3)
Effects of Foreign Exchange	(1)	(8)
Balance at End of Year	**226**	**252**

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	2006	2005
Capitalized for a Period of One Year or Less	179	165
Capitalized for a Period of Greater than One Year	47	87
Balance at End of Year	**226**	**252**
Number of Projects that have Exploratory Well Costs Capitalized for a Period Greater than One Year	4	3

As at December 31, 2006, we have exploratory costs that have been capitalized for more than one year relating to our interest in an exploratory block, offshore Nigeria ($14 million), our interest in an exploratory block in the Gulf of Mexico ($16 million), our coalbed methane exploratory activities in Canada ($10 million) and an exploratory block in the North Sea ($7 million). Our

capitalized costs in Nigeria include capital spending for four successful wells. Development plans are currently being prepared for this area. We have capitalized costs related to successful wells drilled in the Gulf of Mexico and the North Sea. In Canada, we have capitalized exploratory costs relating to our coalbed methane projects. We are assessing all of these wells and projects, and we are working with our partners to prepare development plans.

7. DERIVATIVE INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

(a) Carrying value and estimated fair value of derivative and financial instruments

The carrying values, fair values and unrecognized gains or losses on our outstanding derivatives and long-term financial assets and liabilities at December 31 are:

	2006			2005		
	Carrying Value	Fair Value	Unrecognized Gain (Loss)	Carrying Value	Fair Value	Unrecognized Gain (Loss)
Commodity Price Risk						
Non-Trading Activities						
Crude Oil Put Options	19	19	–	4	4	–
Fixed-Price Natural Gas Contracts	(96)	(96)	–	(175)	(175)	–
Natural Gas Swaps	(8)	(8)	–	29	29	–
Trading Activities						
Crude Oil and Natural Gas	372	372	–	161	161	–
Future Sale of Gas Inventory	–	25	25	–	(35)	(35)
Foreign Currency Risk						
Non-Trading Activities	–	–	–	14	14	–
Trading Activities	(12)	(12)	–	8	8	–
Total Derivatives	**275**	**300**	**25**	**41**	**6**	**(35)**
Financial Assets and Liabilities						
Long-Term Debt	(4,673)	(4,728)	(55)	(3,687)	(3,863)	(176)

The estimated fair value of all derivative instruments is based on quoted market prices and, if not available, on estimates from third-party brokers or dealers. The carrying value of cash and cash equivalents, restricted cash, margin deposits, amounts receivable and short-term obligations approximates their fair value because the instruments are near maturity.

(b) Commodity price risk management

Non-Trading Activities

We generally sell our crude oil and natural gas under short-term market-based contracts.

Crude oil put options

In 2006, we purchased WTI crude oil put options to provide a base level of price protection without limiting our upside to higher prices. These options establish an annual average WTI floor price of US$50/bbl in 2007 on 105,000 bbls/d at a cost of $26 million. In 2004, we purchased WTI crude oil put options to manage the commodity price risk exposure of a portion of our oil production in 2006 and 2005. These options established an annual average WTI floor price of US$38/bbl in 2006 and US$43/bbl in 2005 at a cost of $144 million. The 2006 and 2005 WTI crude oil put options were not used and have expired. The 2007

WTI crude oil put options are stated at fair value and are included in deferred charges and other assets as they settle beyond 12 months from December 31, 2006. Any change in fair value is included in marketing and other on the Consolidated Statement of Income.

	Notional Volumes (bbls/d)	Term	Average Price (WTI) (US$/bbl)	Fair Value (Cdn$ millions)
WTI Crude Oil Put Options	105,000	2007	50	**19**

Fixed price natural gas contracts and natural gas swaps

In July and August 2005, we sold certain Canadian oil and gas properties, and we retained fixed-price natural gas sales contracts that were previously associated with those properties (see Note 14). Since these contracts are no longer used in the normal course of our oil and gas operations, they have been included in our Consolidated Balance Sheet at fair value. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

	Notional Volumes (Gj/d)	Term	Price ($/Gj)	Fair Value (Cdn$ millions)
Fixed-Price Natural Gas Contracts	15,514	2007	2.46	(22)
	15,514	2008-2010	2.56-2.77	(74)
				(96)

Following the sale of the Canadian oil and gas properties, we entered into natural gas swaps to economically hedge our exposure to the fixed-price natural gas contracts. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

	Notional Volumes (Gj/d)	Term	Price ($/Gj)	Fair Value (Cdn$ millions)
Natural Gas Swaps	15,514	2007	7.60	(6)
	15,514	2008-2010	7.60	(2)
				(8)

Trading Activities

Crude oil and natural gas

We enter into physical purchase and sales contracts as well as financial commodity contracts to enhance our price realizations and lock-in our margins. The physical and financial commodity contracts (derivative contracts) are stated at market value. The $372 million fair value of the commodity contracts at December 31, 2006 is included in the Consolidated Balance Sheet and any change in fair value is included in marketing and other in the Consolidated Statement of Income.

Future sale of gas inventory

We have certain NYMEX futures contracts and swaps in place, which effectively lock-in our margins on the future sale of our natural gas inventory in storage. We have designated, in writing, some of these derivative contracts as cash flow hedges of the

future sale of our storage inventory. As a result, gains and losses on these designated futures contracts and swaps are recognized in net income when the inventory in storage is sold. The principal terms of these outstanding contracts and the unrecognized gains at December 31, 2006 are:

	Hedged Volumes (mmbtu)	Month	Average Price (US$/mcf)	Unrecognized Gain (Cdn$ millions)
NYMEX Natural Gas Futures	5,580,000	January 2007	10.73	**25**

In late 2006, we de-designated certain futures contracts that had been designated as cash flow hedges of future sales of our natural gas in storage. These contracts were de-designated since it became uncertain that the future sales of natural gas would occur within the designated time frame. As it is reasonably possible that the future sales may take place as designated at the inception of the hedging relationship, gains of $65 million on the futures contracts have been deferred and will be recognized in net income in 2007 in the originally designated time frame.

(c) Foreign currency exchange rate risk management

Non-Trading Activities

US dollar call options—Canexus

The operations of Canexus are exposed to changes in the US-dollar exchange rate as a portion of its sales are denominated in US dollars. Canexus periodically purchases US-dollar call options to reduce this exposure to fluctuations in the Canadian-US dollar exchange rate. Under outstanding option contracts at December 31, 2006, Canexus LP had the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.85 for the period August 16, 2006 to January 10, 2007 and has the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.87 for the period January 10, 2007 to July 11, 2007. The fair value of these contracts at December 31, 2006 was immaterial and changes in fair value are included in marketing and other in the Consolidated Statement of Income.

Foreign currency swap

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. During the year, we held a foreign currency derivative instrument that obligated us and the counterparty to exchange principal and interest amounts. In November 2006, we paid US$37 million and received Cdn$50 million to settle the foreign currency swap (see Note 8). The change in fair value was included in marketing and other in the Consolidated Statement of Income.

Other

The foreign exchange gains or losses related to our designated debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31 are as follows:

(US$ millions)	2006	2005
Net Investment in Self-Sustaining Foreign Operations	4,534	4,357
US-Dollar Debt	3,761	2,700

We also have small exposures to currencies other than the US dollar. A portion of our United Kingdom operating expenses, capital spending and future asset retirement expenditures is denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies.

Trading Activities

Our sales and purchases of crude oil and natural gas are generally transacted in or referenced to the US dollar, as are most of the financial commodity contracts used by our marketing group. However, we pay for many of our purchases in Canadian dollars. We enter into US-dollar forward contracts and swaps to manage this exposure. Losses of $12 million on our US-dollar forward contracts and swaps at December 31, 2006 are included in the Consolidated Balance Sheet, and any change in fair value is included in marketing and other in the Consolidated Statement of Income.

(d) Total carrying value of derivative contracts related to trading activities

Amounts related to derivative instruments held by our marketing operation are equal to fair value as we use mark-to-market accounting, and are as follows at December 31:

	2006	2005
Accounts Receivable	731	382
Deferred Charges and Other Assets [1] (Note 10)	153	232
Total Derivative Contract Assets	**884**	**614**
Accounts Payable and Accrued Liabilities	325	321
Deferred Credits and Other Liabilities [1] (Note 11)	199	124
Total Derivative Contract Liabilities	**524**	**445**
Total Derivative Contract Net Assets [2]	**360**	**169**

Notes:

1 *These derivative instruments settle beyond 12 months and are considered non-current.*

2 *Comprised of $372 million (2005—$161 million) related to commodity contracts and losses of $12 million (2005—$8 million) related to US-dollar forward contracts and swaps.*

As a physical energy marketer, we match the contract months of our derivative instruments with the contract months of our physical sales and purchases. As a result, our disclosure with respect to derivative instruments includes amounts with no ongoing commodity price or foreign currency risk as at December 31, 2006. Excluding such amounts, derivative contracts included in accounts receivable at December 31, 2006 amounted to $460 million (December 31, 2005 - $382 million) and derivative contracts included in accounts payable and accrued liabilities amounted to $312 million (December 31, 2005 - $290 million).

Our exchange-traded derivative contracts are subject to margin deposit requirements. We are required to advance cash to counterparties in order to satisfy these requirements. We have margin deposits of $197 million (December 31, 2005—nil), which have been included in restricted cash and margin deposits on our Consolidated Balance Sheet at December 31, 2006.

(e) Interest rate risk management

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2006, fixed-rate borrowings comprised 73% (2005—95%) of our long-term debt at an effective average rate of 6.3% (2005—6.3%). During the year, we periodically drew on our floating-rate, unsecured, committed term credit facilities. We had no interest rate swaps outstanding in 2006 or 2005.

(f) Credit risk management

A substantial portion of our accounts receivable are with counterparties in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We assess the financial strength of our counterparties, including those involved in marketing and other commodity arrangements, and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event downgrades to non-investment grade credit ratings occur. Credit risk,

including credit concentrations, is routinely reported to our Risk Management Committee. We also use standard agreements that allow for the netting of exposures associated with a single counterparty. We believe this minimizes our overall credit risk.

8. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	2006	2005
Canexus LP Term Credit Facilities (US$149 million) (a)	174	171
Term Credit Facilities (US$925 million) (b)	1,078	–
Debentures, due 2006 (c)	–	93
Medium-Term Notes, due 2007 (d)	150	150
Medium-Term Notes, due 2008 (e)	125	125
Notes, due 2013 (US$500 million) (f)	583	583
Notes, due 2015 (US$250 million) (g)	291	292
Notes, due 2028 (US$200 million) (h)	233	233
Notes, due 2032 (US$500 million) (i)	583	583
Notes, due 2035 (US$790 million) (j)	920	921
Subordinated Debentures, due 2043 (US$460 million) (k)	536	536
Total	**4,673**	**3,687**

(a) Canexus LP term credit facilities

Canexus LP has $350 million of committed, secured term credit facilities, which are available until 2010. At December 31, 2006, $174 million (US$149 million) was drawn on these facilities (December 31, 2005—$171 million). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at floating rates. The term credit facilities are secured by a floating charge debenture over all of Canexus LP's assets and by certain guarantees, security interests and subordination agreements provided by certain affiliates of Canexus LP (which do not include Nexen). During 2006, the weighted-average interest rate on the Canexus LP term credit facilities was 5.9% (2005—4.8%).

(b) Term credit facilities

We have committed, unsecured, term credit facilities of $3.6 billion, which are available until 2011. At December 31, 2006, $1,078 million (US$925 million) was drawn on these facilities (December 31, 2005—nil). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable monthly at floating rates. During 2006, the weighted-average interest rate was 5.7% (2005—4.4%). At December 31, 2006, $294 million of these facilities were utilized to support outstanding letters of credit (December 31, 2005—$250 million).

(c) Debentures, due 2006

During November 1996, we issued $100 million of unsecured 10 year redeemable debentures. Interest was payable semi-annually at a rate of 6.85%. In December 1996, $50 million of this obligation was effectively converted through a foreign currency swap with a Canadian chartered bank to a US$37 million liability bearing interest at 6.75% for the term of the debentures. In November 2006, we repaid the outstanding debentures of $100 million and realized a gain of $7 million on the foreign currency swap.

(d) Medium-term notes, due 2007

During July 1997, we issued $150 million of notes. Interest is payable semi-annually at a rate of 6.45%, and the principal is to be repaid in July 2007. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining

term of the notes plus 0.125%. Amounts due July 2007 have not been included in current liabilities as we expect to refinance this amount with our term credit facilities.

(e) Medium-term notes, due 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3%, and the principal is to be repaid in June 2008. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(f) Notes, due 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05%, and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(g) Notes, due 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.20%, and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.15%.

(h) Notes, due 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4%, and the principal is to be repaid in May 2028. We may redeem part or all of the notes any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

(i) Notes, due 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875%, and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%.

(j) Notes, due 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875%, and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(k) Subordinated debentures, due 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(l) Long-term debt repayments

2007	150
2008	125
2009	–
2010	174
2011	1,078
Thereafter	3,146
Total Debt Repayments	**4,673**

(m) Debt covenants

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2006, we were in compliance with all covenants.

(n) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $632 million. At December 31, 2006, $158 million (US$136 million) was drawn under these facilities (December 31, 2005—nil). We have also utilized $252 million of these facilities to support outstanding letters of credit at December 31, 2006 (2005—$468 million). Interest is payable at floating rates. During 2006, the weighted-average interest rate on our short-term borrowings was 5.5% (2005—3.6%).

(o) Interest expense

	2006	2005	2004
Long-Term Debt	275	260	182
Other	19	15	12
Total	294	275	194
Less: Capitalized	(241)	(178)	(51)
Total Interest Expense	**53**	**97**	**143**

Capitalized interest relates to and is included as part of the cost of oil and gas and Syncrude properties. The capitalization rates are based on our weighted-average cost of borrowings.

9. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

	2006	2005
Balance at Beginning of Year	611	468
Obligations Assumed with Development Activities	75	72
Obligations Discharged with Disposed Properties	(1)	(37)
Expenditures Made on Asset Retirements	(44)	(34)
Accretion	37	26
Revisions to Estimates	(10)	138
Effects of Foreign Exchange	36	(22)
Balance at End of Year [1, 2]	**704**	**611**

Notes:

1 *Obligations due within 12 months of $21 million (2005—$21 million) have been included in accounts payable and accrued liabilities.*

2 *Obligations relating to our oil and gas activities amount to $658 million (2005—$564 million) and obligations relating to our chemicals business amount to $46 million (2005—$47 million).*

Our total estimated undiscounted asset retirement obligations amount to $1,770 million. We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 5.7%. Approximately $97 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile. The estimated future recoverable reserves at Syncrude are significant and given the long life of this asset, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant can continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the lives of the assets are determinable.

10. DEFERRED CHARGES AND OTHER ASSETS

	2006	2005
Long-Term Marketing Derivative Contracts (Note 7d)	153	232
Deferred Financing Costs	59	63
Asset Retirement Remediation Fund	13	14
Crude Oil Put Options (Note 7a)	19	4
Other	74	85
Total	**318**	**398**

11. DEFERRED CREDITS AND OTHER LIABILITIES

	2006	2005
Fixed-Price Natural Gas Contracts (Note 7b)	74	128
Long-Term Marketing Derivative Contracts (Note 7d)	199	124
Deferred Transportation Revenue	89	87
Stock-Based Compensation Liability	6	53
Defined Benefit Pension Obligations (Note 16)	48	39
Capital Lease Obligations	48	9
Other	52	39
Total	**516**	**479**

12. SHAREHOLDERS' EQUITY

(a) Authorized capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

(b) Issued common shares and dividends

(thousands of shares)	2006	2005	2004
Beginning of Year	261,141	258,399	251,212
Issue of Common Shares for Cash			
Exercise of Tandem Options	846	1,823	5,902
Dividend Reinvestment Plan	276	605	895
Employee Flow-through Shares	250	314	390
End of Year	**262,513**	**261,141**	**258,399**
Dividends Declared per Common Share ($/share)	**0.20**	**0.20**	**0.20**
Cash Consideration (Cdn$ millions)			
Exercise of Tandem Options	16	29	93
Dividend Reinvestment Plan	16	20	21
Employee Flow-through Shares	16	9	10
	48	**58**	**124**

At December 31, 2006, there were 498,831 common shares (2005—774,915; 2004—1,379,874) reserved for issuance under the Dividend Reinvestment Plan.

(c) Tandem options

In May 2004, our shareholders approved the modification of our stock option plan to a tandem option plan by including a cash feature. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price.

Similar to our stock appreciation rights, we use the intrinsic-value method to recognize compensation expense associated with our tandem options. Obligations are accrued on a graded-vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded-vested options outstanding.

Upon modification of the stock option plan, we were required to recognize an obligation for our tandem options. This obligation represented the difference between the market value of our common shares and the weighted-average exercise price of the options. As a result, we recognized an obligation of $85 million for the graded-vested portion of the options outstanding on June 30, 2004. In the second quarter of 2004, a one-time, non-cash charge of $82 million was included in general and administrative expense, net of $3 million previously expensed in respect of our original stock options.

Following the introduction of the *American Job Creation Act of 2004* in the US, stock options awarded to our US employees between December 1, 2004 and December 1, 2005 did not include a tandem option cash feature. We use the fair-value method to recognize compensation expense associated with these options. The expense is recognized over the vesting period of the options with a corresponding increase to contributed surplus. This resulted in compensation expense in 2006 of $2 million (2005—$2 million; 2004—$0.1 million), which was included in general and administrative expense. In 2005, US tax regulations were modified and as a result, tandem options have been issued to our US employees after December 1, 2005. These options are expensed using the intrinsic-method described above.

We have granted options to purchase common shares to directors, officers and employees. Each option permits the holder to purchase one Nexen common share at the stated exercise price. Options granted prior to February 2001 vest over four years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over three years and are exercisable on a cumulative basis over five years. At the time of grant, the exercise price equals the market price. The following options have been granted:

	2006		2005		2004	
	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)
Balance at Beginning of Year	15,315	28	16,276	20	18,406	17
Granted	2,400	63	3,392	55	4,224	25
Exercised for Stock	(846)	18	(1,823)	16	(5,902)	15
Surrendered for Cash	(1,522)	18	(2,089)	17	(289)	17
Forfeited	(105)	38	(441)	22	(163)	17
Balance at End of Year	**15,242**	**35**	**15,315**	**28**	**16,276**	**20**
Options Exercisable at End of Year	9,345	24	8,131	19	8,455	17
Common Shares Reserved for Issuance Under the Tandem Option Plan	16,235		17,290		19,172	

The range of exercise prices of options outstanding and exercisable at December 31, 2006 is as follows:

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Years to Expiry (years)	Number of Options (thousands)	Weighted Average Exercise Price ($/option)
$5.00 to $9.99	178	9	2	178	9
$10.00 to $14.99	788	14	2	788	14
$15.00 to $19.99	3,032	18	3	3,032	18
$20.00 to $24.99	2,792	23	2	2,462	22
$25.00 to $29.99	2,768	25	3	1,778	25
$30.00 to $34.99	14	31	3	2	31
$35.00 to $39.99	–	–	–	–	–
$40.00 to $44.99	2	40	4	1	40
$45.00 to $49.99	13	47	4	5	47
$50.00 to $54.99	3,254	55	4	1,099	54
$55.00 to $59.99	12	57	4	–	–
$60.00 to $64.99	2,383	63	5	–	–
$65.00 to $69.99	3	66	4	–	–
$70.00 to $74.99	3	71	5	–	–
Total Options	**15,242**			**9,345**	

(d) Stock appreciation rights

Under our stock appreciation rights (StARs) plan established in 2001, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares. At the time of grant, the exercise price equals the market price. The following stock appreciation rights have been granted:

	2006		2005		2004	
	StARs (thousands)	Weighted Average Exercise Price ($/StAR)	StARs (thousands)	Weighted Average Exercise Price ($/StAR)	StARs (thousands)	Weighted Average Exercise Price ($/StAR)
Balance at Beginning of Year	5,964	30	6,436	22	4,809	18
Granted	2,254	63	1,443	55	2,609	25
Exercised for Cash	(1,082)	21	(1,455)	19	(867)	16
Forfeited	(191)	38	(460)	23	(115)	18
Balance at End of Year	**6,945**	**42**	**5,964**	**30**	**6,436**	**22**
StARs Exercisable at End of Year	3,076	27	2,426	21	2,021	17

The range of exercise prices of StARs outstanding and exercisable at December 31, 2006 is as follows:

	Outstanding StARs			Exercisable StARs	
	Number of StARs (thousands)	Weighted Average Exercise Price ($/StAR)	Weighted Average Years to Expiry (years)	Number of StARs (thousands)	Weighted Average Exercise Price ($/StAR)
$15.00 to $19.99	513	17	1	513	17
$20.00 to $24.99	991	22	2	985	22
$25.00 to $29.99	1,859	25	3	1,138	25
$30.00 to $34.99	18	33	3	6	33
$35.00 to $39.99	9	37	4	1	37
$40.00 to $44.99	8	41	4	3	41
$45.00 to $49.99	38	48	4	12	48
$50.00 to $54.99	1,256	55	4	418	55
$55.00 to $59.99	29	57	4	–	–
$60.00 to $64.99	2,213	63	5	–	–
$65.00 to $69.99	11	66	4	–	–
Total StARs	**6,945**			**3,076**	

13. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share from continuing operations using net income from continuing operations divided by the weighted-average number of common shares outstanding. We calculate basic earnings per common share using net income and the weighted-average number of common shares outstanding. We calculate diluted earnings per common share from continuing operations and diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2006	2005	2004
Weighted-Average Number of Common Shares Outstanding	262.1	260.4	257.3
Shares Issuable Pursuant to Stock Options	13.9	13.4	13.1
Shares to be Purchased from Proceeds of Stock Options	(7.1)	(7.4)	(9.8)
Weighted-Average Number of Diluted Common Shares Outstanding	**268.9**	**266.4**	**260.6**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2006, we excluded 211,283 options (2005—280,708; 2004—348,200), because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding stock options were the only potential dilutive instruments.

14. DISCONTINUED OPERATIONS

In the third quarter of 2005, we sold certain Canadian conventional oil and gas properties in southeast Saskatchewan, northwest Saskatchewan, northeast British Columbia and the Alberta foothills. The results of operations of these properties have been presented as discontinued operations. The sales closed in the third quarter of 2005 with net proceeds of $900 million after closing adjustments, and we realized gains of $225 million. These gains are net of losses attributable to pipeline contracts and fixed-price gas sales contracts associated with these properties that we have retained, but no longer use in connection with our oil and gas business.

During the fourth quarter of 2004, we concluded production from our Buffalo field, offshore Australia. The results of our operations in Australia have been presented as discontinued operations, as we have no plans to continue operations in the country. Remediation and abandonment activities have been completed, and no gain or loss was recognized.

The results of operations from these properties in Australia and Canada are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2005	2004		
	Canada	Canada	Australia	Total
Revenues and Other Income				
Net Sales	154	232	75	307
Marketing and Other	–	1	–	1
Gain on Disposition of Assets	225	–	–	–
	379	233	75	308
Expenses				
Operating	27	40	53	93
Depreciation, Depletion, Amortization and Impairment	28	70	9	79
Exploration Expense	1	3	–	3
Income before Income Taxes	323	120	13	133
Provision for Future Income Taxes	(129)	50	–	50
Net Income from Discontinued Operations	**452**	**70**	**13**	**83**
Earnings per Common Share ($/share)				
Basic (Note 13)	1.74	0.27	0.05	0.32
Diluted (Note 13)	1.70	0.27	0.05	0.32

There were no assets and liabilities related to discontinued operations as at December 31, 2006.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

	2007	2008	2009	2010	2011	Thereafter
Operating Leases	44	109	127	123	117	232
Transportation and Storage Commitments	424	165	97	70	53	118
	468	**274**	**224**	**193**	**170**	**350**

In June 2003, a subsidiary of Occidental Petroleum Corporation (Occidental) initiated an arbitration against us at the International Court of Arbitration of the International Chamber of Commerce (ICC Court) regarding an Area of Mutual Interest agreement relating to certain portions of Block 51 in the Republic of Yemen. In April 2006, the ICC Court concluded that we breached this agreement and as a result, Occidental was entitled to monetary damages. In late 2006, we agreed to settle the arbitration with Occidental for US$135 million. No further amounts are expected to be payable under the settlement. This amount was accrued and included in other expenses in our Consolidated Statement of Income during 2006.

We have a number of lawsuits and claims pending including income tax reassessments (see Note 18), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2006, total rental expense was $49 million (2005—$47 million; 2004—$45 million).

From time to time, we enter into certain types of contracts that require us to indemnify parties against possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary, and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to such matters, would not have a material adverse effect on our liquidity, financial condition or results of operations.

16. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen and Canexus have contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan. Under the defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1%, to a maximum increase of 5%. On the establishment of Canexus in 2005, the portion of the projected benefit obligation and fair value of plan assets relating to Canexus employees was transferred to Canexus from Nexen.

(a) Defined benefit pension plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2006			2005		
	Nexen	Canexus	Syncrude	Nexen	Canexus	Syncrude
Change in Projected Benefit Obligation (PBO)						
Beginning of Year	223	49	109	217	–	91
Service Cost	16	3	5	15	1	4
Interest Cost	12	3	5	12	1	5
Plan Participants' Contributions	3	1	1	3	–	1
Actuarial Loss/(Gain)	9	2	–	33	(2)	11
Benefits Paid	(11)	–	(4)	(8)	–	(3)
Transfer to Canexus	–	–	–	(49)	49	–
End of Year [1]	**252**	**58**	**116**	**223**	**49**	**109**
Change in Fair Value of Plan Assets						
Beginning of Year	146	40	58	171	–	50
Actual Return on Plan Assets	23	6	8	18	–	6
Employer's Contribution	24	3	5	2	–	4
Plan Participants' Contributions	3	1	1	3	–	1
Benefits Paid	(11)	–	(3)	(8)	–	(3)
Transfer to Canexus	–	–	–	(40)	40	–
End of Year	**185**	**50**	**69**	**146**	**40**	**58**
Reconciliation of Funded Status						
Funded Status [2]	(67)	(8)	(47)	(77)	(9)	(51)
Unamortized Transitional Obligation	–	–	–	1	–	–
Unamortized Prior Service Costs	3	–	–	3	–	–
Unamortized Net Actuarial Loss	39	7	32	44	9	38
Pension Liability	**(25)**	**(1)**	**(15)**	**(29)**	**–**	**(13)**
Pension Liability Recognized						
Deferred Charges and Other Assets	10	–	–	–	–	–
Accounts Payable and Accrued Liabilities	(1)	–	(2)	(1)	–	(2)
Other Deferred Credits and Liabilities (Note 11)	(34)	(1)	(13)	(28)	–	(11)
Pension Liability	**(25)**	**(1)**	**(15)**	**(29)**	**–**	**(13)**
Assumptions (%)						
Accrued Benefit Obligation at December 31						
Discount Rate	5.00	5.00	5.00	5.25	5.25	5.00
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00	4.00	4.00
Benefit Cost for Year Ended December 31 [3]						
Discount Rate	5.25	5.25	5.00	5.00	5.00	5.00
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00	4.00	4.00
Long-Term Annual Rate of Return on Plan Assets [4]	7.00	6.50	8.50	7.00	6.50	8.50

Notes:

1 *The accumulated benefit obligations (the projected benefit obligation excluding future salary increases) of the Nexen and Canexus plans were $180 million and $44 million at December 31, 2006, respectively (2005—$161 million and $36 million, respectively). Nexen's supplemental pension plan's accumulated benefit obligation was $35 million at December 31, 2006 (2005—$29 million). Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $89 million at December 31, 2006 (2005—$82 million).*

2 *Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2006, the PBO for Nexen's supplemental benefits was $53 million (2005—$43 million) and $1 million for Canexus (2005—$1 million).*

3 *The assumptions have been used to calculate the recognized expense for Nexen and Canexus. There were no changes to the assumptions between the measurement date and December 31, 2006. Syncrude's measurement date was December 31, 2006.*

4 *The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.*

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2006	2005	2004
Nexen			
Cost of Benefits Earned by Employees	16	15	8
Interest Cost on Benefits Earned	12	12	12
Actual Return on Plan Assets	(23)	(18)	(16)
Actuarial Losses	9	33	10
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	14	42	14
Difference Between Actual and Expected Return on Plan Assets	12	8	5
Difference Between Actual and Recognized Actuarial Losses	(7)	(32)	(10)
Difference Between Actual and Recognized Past Service Costs	1	–	1
Net Pension Expense	20	18	10
Canexus			
Cost of Benefits Earned by Employees	3	1	–
Interest Cost on Benefits Earned	3	1	–
Actual Return on Plan Assets	(6)	–	–
Actuarial (Gains)/Losses	2	(2)	–
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	2	–	–
Difference Between Actual and Expected Return on Plan Assets	3	(1)	–
Difference Between Actual and Recognized Actuarial Gains	(2)	2	–
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	3	1	–
Syncrude			
Cost of Benefits Earned by Employees	5	4	3
Interest Cost on Benefits Earned	5	5	5
Actual Return on Plan Assets	(8)	(6)	(5)
Actuarial Losses	–	11	7
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	2	14	10
Difference Between Actual and Expected Return on Plan Assets	3	2	1
Difference Between Actual and Recognized Actuarial Losses	2	(8)	(6)
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	7	8	5
Total Net Pension Expense	**30**	**27**	**15**

(b) Plan asset allocation at December 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committees of Nexen and Canexus. Nexen's and Canexus' investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's investment policies.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

(%)	Expected 2007	2006	2005
Nexen			
Equity Securities	65	60	60
Debt Securities	35	40	40
Real Estate	–	–	–
Other	–	–	–
Total	**100**	**100**	**100**
Canexus			
Equity Securities	50	60	60
Debt Securities	50	40	40
Real Estate	–	–	–
Other	–	–	–
Total	**100**	**100**	**100**
Syncrude			
Equity Securities	70	70	70
Debt Securities	30	30	30
Real Estate	–	–	–
Other	–	–	–
Total	**100**	**100**	**100**

(c) Defined contribution pension plans

Under these plans, pension benefits are based on plan contributions. During 2006, Canadian pension expense for these plans was $4 million (2005—$4 million; 2004—$4 million). During 2006, US pension expense for these plans was $4 million (2005—$4 million; 2004—$3 million).

(d) Post-retirement benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded. The present value of Nexen employees' future post retirement benefits at December 31, 2006 was $6 million (2005—$4 million) and $2 million for Canexus (2005—$2 million).

(e) Employer funding contributions and benefit payments

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we make contributions on behalf of our employees and no further obligation exists. Our funding contributions for the defined benefit plans are:

Defined Benefit Contributions	Expected 2007	2006	2005
Nexen	11	24	2
Canexus	2	3	–
Syncrude	5	5	4
Total Funding Contributions	**18**	**32**	**6**

Our most recent funding valuation was prepared as of June 30, 2006. Our next funding valuation is required by June 30, 2009. Canexus' most recent funding valuation was prepared as of August 18, 2005, and their next funding valuation is required by December 31, 2007. Syncrude's most recent funding valuation was prepared as of December 31, 2006, and their next funding valuation is December 31, 2008.

Our total benefit payments in 2006 were $11 million for Nexen (2005—$8 million). Our share of Syncrude's total benefit payments in 2006 was $4 million (2005—$3 million). Our estimated future payments are as follows:

	Defined Benefit			Other		
	Nexen	**Canexus**	**Syncrude**	**Nexen**	**Canexus**	**Syncrude**
2007	9	1	3	1	–	–
2008	9	1	3	2	–	–
2009	10	1	4	2	–	–
2010	11	1	4	2	–	–
2011	11	2	4	2	–	–
2012—2016	71	15	29	18	–	1

17. MARKETING AND OTHER

	2006	**2005**	**2004**
Marketing Revenue, Net	1,309	847	608
Business Interruption Insurance Proceeds [1]	154	2	10
Change in Fair Value of Crude Oil Put Options	(11)	(196)	56
Interest	36	29	12
Foreign Exchange Losses	(72)	(19)	(13)
Gains on Disposition of Assets [2]	4	4	24
Other	30	35	16
Total Marketing and Other	**1,450**	**702**	**713**

Notes:

1 *In 2006, we received business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005 and by generator failures in our UK operations in 2005.*

2 *Gains on disposition of assets resulted from the sale of minor oil and gas assets in our Canadian operations in 2006 and 2004 and from the sale of our Ejulebe assets, offshore Nigeria in 2005.*

18. INCOME TAXES

(a) Temporary differences

	2006		2005	
	Future Income Tax Assets	**Future Income Tax Liabilities**	**Future Income Tax Assets**	**Future Income Tax Liabilities**
Property, Plant and Equipment, Net	26	2,420	31	1,780
Tax Losses Carried Forward	594	–	370	–
Deferred Income	–	48	–	175
Recoverable Taxes	–	–	9	–
Total [1]	**620**	**2,468**	**410**	**1,955**

Note:

1 *2006 includes future income tax assets of $479 million that we expect to realize in the following twelve months have been included in current assets.*

(b) Canadian and foreign income taxes

	2006	2005	2004
Income from Continuing Operations before Income Taxes			
Canadian	(352)	(396)	24
Foreign	1,648	1,326	1,003
	1,296	930	1,027
Provision for Income Taxes			
Current			
Canadian	14	1	6
Foreign	354	338	242
	368	339	248
Future			
Canadian	(96)	(206)	(3)
Foreign	411	101	72
	315	(105)	69
Total Provision for Income Taxes	**683**	**234**	**317**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, Colombia, the United Kingdom and the United States and include Yemen cash taxes of $286 million (2005—$296 million; 2004—$227 million).

(c) Reconciliation of effective tax rate to the Canadian statutory tax rate

	2006	2005	2004
Income before Income Taxes From Continuing Operations	1,296	930	1,027
Provision for Income Taxes Computed at the Canadian Statutory Rate	401	318	354
Add (Deduct) the Tax Effect of:			
Royalties, Rentals and Similar Payments to Provincial Governments	15	24	20
Resource Allowance and Provincial Tax Rebates	(15)	(24)	(29)
Lower Foreign Tax Rates	(9)	(40)	(22)
Additional Canadian Tax on Canadian Resource Income	10	6	7
Lower Tax Rates on Capital Gains	(3)	(54)	–
Federal and Provincial Capital Tax	13	5	6
Effect of Changes in Tax Rates	245	–	(15)
Non-Deductible Expenses and Other	26	(1)	(4)
Provision for Income Taxes	**683**	**234**	**317**

During the first quarter of 2006, we recorded a future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom. Legislation was introduced to the United Kingdom parliament during the first quarter to increase the supplemental tax rate from 10% to 20%, effective January 1, 2006.

In 2006 and 2004, the federal and some provincial governments in Canada reduced statutory income tax rates. This reduced our liability and provision for future income taxes by $32 million and $15 million in 2006 and 2004, respectively.

(d) Available unused tax losses and tax contingencies

At December 31, 2006 and 2005, we had unused tax losses totalling $1,258 million and $965 million, respectively, mostly from our UK operations. The majority of these losses have no expiry date.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an adequate provision for income taxes based on available information.

At the time of acquisition, Wascana, a predecessor company, had outstanding taxation issues in dispute from prior taxation years. Wascana disagreed with issues raised and has filed notices of objection. The value of the tax pools acquired at the time of acquisition reflected our evaluation of the potential impact of these issues.

19. CASH FLOWS

(a) Charges and credits to income not involving cash

	2006	2005	2004
Depreciation, Depletion, Amortization and Impairment	1,124	1,052	674
Stock-Based Compensation	101	428	74
Gains on Disposition of Assets	(4)	(4)	(24)
Provision for Future Income Taxes	315	(105)	69
Change in Fair Value of Crude Oil Put Options	11	196	(56)
Non-Cash Items included in Discontinued Operations	–	(325)	132
Unamortized Issue Costs on Preferred Securities Redemption	–	–	11
Gain on Dilution of Interest in Chemicals Business	–	(193)	–
Net Income Attributable to Non-Controlling Interests	12	8	–
Other	70	24	26
Total	**1,629**	**1,081**	**906**

(b) Changes in non-cash working capital

	2006	2005	2004
Accounts Receivable	345	(1,078)	(454)
Inventories and Supplies	(302)	(163)	(106)
Other Current Assets	(14)	(10)	44
Accounts Payable and Accrued Liabilities	(72)	982	650
Other	–	20	(12)
Total	**(43)**	**(249)**	**122**
Relating to:			
Operating Activities	(177)	(195)	(122)
Investing Activities	134	(54)	244
Total	**(43)**	**(249)**	**122**

(c) Other cash flow information

	2006	2005	2004
Interest Paid	278	237	190
Income Taxes Paid	398	325	249

In 2004, other operating activity cash outflows include $144 million for the purchase of crude oil put options.

20. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in West Africa and Colombia.

Energy Marketing: Our marketing group sells our crude oil and natural gas, markets third-party crude oil and natural gas and engages in energy trading, including electricity generation.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from mining bitumen in the oil sands in northern Alberta.

Chemicals: Through our investment in Canexus LP, we manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine, acid and caustic soda. We produce sodium chlorate at four facilities in Canada and one in Brazil. We produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses with the exception of Chemicals. Identifiable assets are those used in the operations of the segments.

2006 Operating and Geographic Segments

	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
(Cdn$ millions)	Yemen	Canada	US	UK	Other Countries [1]					
Net Sales [2]	1,328	459	629	477	139	51	446	407 [3]	–	3,936
Marketing and Other	8	7	81 [4]	85 [5]	1	1,309	–	6	(47) [6]	1,450
	1,336	466	710	562	140	1,360	446	413	(47)	5,386
Less: Expenses										
Operating	151	143	106	80	8	31	187	249	–	955
Depreciation, Depletion, Amortization and Impairment [7]	327	162	296	216	10	12	33	40	28	1,124
Transportation and Other	6	33	–	–	1	789	18	40	154 [8]	1,041
General and Administrative [9]	17	80	58	14	44	112	1	29	200	555
Exploration	4	26	214	46	72 [10]	–	–	–	–	362
Interest	–	–	–	–	–	–	–	11	42	53
Income (Loss) from Continuing Operations before Income Taxes	831	22	36	206	5	416	207	44	(471)	1,296
Less: Provision for (Recovery of) Income Taxes [11]	289	7	13	378 [12]	1	151	66	15	(237)	683
Net Income (Loss) from Continuing Operations	542	15	23	(172)	4	265	141	29	(234)	613
Less: Non-Controlling Interests	–	–	–	–	–	–	–	12	–	12
Net Income (Loss)	**542**	**15**	**23**	**(172)**	**4**	**265**	**141**	**17**	**(234)**	**601**
Identifiable Assets	**464**	**3,923**	**1,620**	**5,490**	**245**	**3,528** [13]	**1,186**	**459**	**241**	**17,156**
Capital Expenditures										
Development and Other	145	1,434	418	596	28	47	86	27	45	2,826
Exploration	37	163	177	62	52	–	–	–	–	491
Proved Property Acquisitions	–	12	–	1	–	–	–	–	–	13
Total Capital Expenditures	**182**	**1,609**	**595**	**659**	**80**	**47**	**86**	**27**	**45**	**3,330**
Property, Plant and Equipment										
Cost	2,404	5,216	2,889	4,710	249	226	1,304	854	286	18,138
Less: Accumulated DD&A	2,128	1,448	1,445	432	78	47	179	494	148	6,399
Net Book Value [2]	**276**	**3,768**	**1,444**	**4,278**	**171**	**179**	**1,125**	**360**	**138**	**11,739**
Goodwill	**–**	**–**	**–**	**325**	**–**	**52**	**–**	**–**	**–**	**377**

Notes:

1. *Includes results of operations from producing activities in Colombia.*
2. *Net sales made from all segments originating in Canada: 1,095*
   PP&E located in Canada: 5,483
3. *Net sales for our chemicals operations include:*

Canada	*139*
United States	*185*
Brazil	*83*
Total	*407*

4. *Includes $80 million of business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005.*
5. *Includes $74 million of business interruption insurance proceeds for generator failures in 2005.*
6. *Includes interest income of $36 million, foreign exchange losses of $72 million and decrease in the fair value of crude oil put options of $11 million.*
7. *Includes an impairment charge of $93 million, primarily relating to two natural gas properties in the Gulf of Mexico.*
8. *Includes $151 million (US$135 million) accrual with respect to the Block 51 arbitration settlement (see Note 15).*
9. *Includes stock-based compensation expense of $210 million.*
10. *Includes exploration activities primarily in Nigeria, Norway and Colombia.*
11. *The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.*
12. *Includes future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom (see Note 18).*
13. *Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.*

2005 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: Yemen	Canada [1]	US	UK	Other Countries [2]	Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
Net Sales [3]	1,377	455	792	366	119	28	397	398 [4]	–	3,932
Marketing and Other	8	3	2	16	4	847	–	15	(193) [5]	702
Gain on Dilution of Interest in Chemicals Business	–	–	–	–	–	–	–	193	–	193
	1,385	458	794	382	123	875	397	606	(193)	4,827
Less: Expenses										
Operating	150	121	96	95	12	30	152	237	–	893
Depreciation, Depletion, Amortization and Impairment	354	140	234	210	13	11	17	51 [6]	22	1,052
Transportation and Other	6	23	1	–	2	641	21	40	62	796
General and Administrative [7]	42	107	88	8	101	89	1	45	328	809
Exploration	12	23	100	51	64 [8]	–	–	–	–	250
Interest	–	–	–	–	–	–	–	3	94	97
Income (Loss) from Continuing Operations before Income Taxes	821	44	275	18	(69)	104	206	230	(699)	930
Less: Provision for (Recovery of) Income Taxes [9]	285	13	98	7	(13)	41	60	15	(272)	234
Net Income (Loss) from Continuing Operations	536	31	177	11	(56)	63	146	215	(427)	696
Less: Non-Controlling Interests	–	–	–	–	–	–	–	8	–	8
Add: Net Income from Discontinued Operations	–	452	–	–	–	–	–	–	–	452
Net Income (Loss)	**536**	**483**	**177**	**11**	**(56)**	**63**	**146**	**207**	**(427)**	**1,140**
Identifiable Assets	**635**	**2,449**	**1,433**	**4,775**	**183**	**3,165** [10]	**1,135**	**482**	**333**	**14,590**
Capital Expenditures										
Development and Other	236	947	148	566	14	16	197	14	24	2,162
Exploration	41	90	211	59	55	–	–	–	–	456
Proved Property Acquisitions	–	17	3	–	–	–	–	–	–	20
Total Capital Expenditures	**277**	**1,054**	**362**	**625**	**69**	**16**	**197**	**14**	**24**	**2,638**
Property, Plant and Equipment										
Cost	2,243	3,631	2,437	4,013	249	177	1,240	827	245	15,062
Less: Accumulated DD&A	1,841	1,311	1,159	216	119	72	171	456	123	5,468
Net Book Value [3]	**402**	**2,320**	**1,278**	**3,797**	**130**	**105**	**1,069**	**371**	**122**	**9,594**
Goodwill	**–**	**–**	**–**	**325**	**–**	**39**	**–**	**–**	**–**	**364**

Notes:

1 *During the third quarter of 2005, we concluded the sale of Canadian conventional oil and gas properties. The results of these properties are shown as discontinued operations (see Note 14).*

2 *Includes results of operations from producing activities in Nigeria and Colombia.*

3 *Net sales made from all segments originating in Canada: 1,014*
PP&E located in Canada: 3,899

4 *Net sales for our chemicals operations include:*

Canada	*132*
United States	*198*
Brazil	*68*
Total	*398*

5 *Includes interest income of $29 million, foreign exchange losses of $19 million, decrease in the fair value of crude oil put options of $196 million and decrease in the fair value of foreign currency call options of $7 million.*

6 *Includes impairment charge of $12 million related to the closure of our sodium chlorate plant in Amherstburg, Ontario.*

7 *Includes stock-based compensation expense of $507 million.*

8 *Includes exploration activities primarily in Nigeria, Colombia and Equatorial Guinea.*

9 *The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.*

10 *Approximately 86% of Marketing's identifiable assets are accounts receivable and inventories.*

2004 Operating and Geographic Segments

	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
(Cdn$ millions)	Yemen	Canada	US	UK [1]	Other Countries [2]					
Net Sales [3]	921	390	811	36	73	14	321	378 [4]	–	2,944
Marketing and Other	5	27	11	–	2	608	–	5	55 [5]	713
	926	417	822	36	75	622	321	383	55	3,657
Less: Expenses										
Operating	109	116	106	6	7	16	125	237	–	722
Depreciation, Depletion, Amortization and Impairment	169	128	258	18	18	10	18	37	18	674
Transportation and Other	5	15	–	–	–	451	12	41	25	549
General and Administrative	4	42	30	–	47	58	1	28	89	299
Exploration	2	18	138	3	82 [6]	–	–	–	–	243
Interest	–	–	–	–	–	–	–	–	143	143
Income (Loss) from Continuing Operations before Income Taxes	637	98	290	9	(79)	87	165	40	(220)	1,027
Less: Provision for (Recovery of) Income Taxes [7]	222	28	104	4	1	28	47	13	(130)	317
Net Income (Loss) from Continuing Operations	415	70	186	5	(80)	59	118	27	(90)	710
Add: Net Income from Discontinued Operations [8]	–	70	–	–	13	–	–	–	–	83
Net Income (Loss)	**415**	**140**	**186**	**5**	**(67)**	**59**	**118**	**27**	**(90)**	**793**
Identifiable Assets	**564**	**1,979**	**1,359**	**4,446**	**218**	**2,030** [9]	**912**	**497**	**378**	**12,383**
Capital Expenditures										
Development and Other	267	491	267	53	24	4	214	58	33	1,411
Exploration	19	46	133	4	64	–	–	–	–	266
Proved Property Acquisitions	–	4	–	–	–	–	–	–	–	4
Total Capital Expenditures	**286**	**541**	**400**	**57**	**88**	**4**	**214**	**58**	**33**	**1,681**
Property, Plant and Equipment										
Cost	2,038	2,603	2,249	3,499	535	157	1,030	815	201	13,127
Less: Accumulated DD&A	1,550	1,195	1,037	16	408	64	155	409	90	4,924
Net Book Value [3]	**488**	**1,408** [10]	**1,212**	**3,483**	**127**	**93**	**875**	**406**	**111**	**8,203**
Goodwill	–	–	–	**339**	–	**36**	–	–	–	**375**

Notes:

1 *On December 1, 2004, we acquired EnCana (UK) Limited (see Note 3).*

2 *Includes results of operations from producing activities in Nigeria, Colombia, and Australia.*

3 *Net sales made from all segments originating in Canada:* *1,242*

PP&E located in Canada: *3,198*

4 *Net sales for our chemicals operations include:*

Canada	*135*
United States	*184*
Brazil	*59*
Total	*378*

5 *Includes interest income of $12 million, foreign exchange losses of $13 million and unrealized mark-to-market gains on crude oil put options of $56 million.*

6 *Includes exploration activities primarily in Nigeria and Colombia.*

7 *The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.*

8 *In the fourth quarter of 2004, we concluded production activities in Australia. During the third quarter of 2005, we concluded the sale of certain Canadian conventional oil and gas properties. The combined results of these dispositions are shown as discontinued operations (see Note 14).*

9 *Approximately 81% of Marketing's identifiable assets are accounts receivable and inventories.*

10 *Excludes PP&E costs of $860 million and accumulated DD&A of $420 million relating to the Canadian properties disposed of during 2005 (see Note 14).*

21. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP
For the Three Years ended December 31, 2006

(Cdn$ millions, except per share amounts)	2006	2005	2004
Revenues and Other Income			
Net Sales	3,936	3,932	2,944
Marketing and Other (ii); (x); (xi)	1,459	687	696
Gain on Dilution of Interest in Chemicals Business	–	193	–
	5,395	4,812	3,640
Expenses			
Operating (iv)	958	903	731
Depreciation, Depletion, Amortization and Impairment (i)	1,124	1,081	716
Transportation and Other (x)	1,037	792	524
General and Administrative (viii); (ix)	597	792	263
Exploration	362	250	243
Interest	53	97	143
	4,131	3,915	2,620
Income from Continuing Operations before Income Taxes	1,264	897	1,020
Provision for Income Taxes			
Current	368	339	248
Deferred (ii) – (xi)	305	(108)	67
	673	231	315
Net Income from Continuing Operations before Non-Controlling Interests	591	666	705
Net Income Attributable to Non-Controlling Interests	12	8	–
Net Income from Continuing Operations	579	658	705
Net Income from Discontinued Operations	–	452	83
Net Income—US GAAP [1]	**579**	**1,110**	**788**
Earnings Per Common Share ($/share)			
Basic (Note 13)			
Net Income from Continuing Operations	2.21	2.52	2.74
Net Income from Discontinued Operations	–	1.74	0.32
	2.21	4.26	3.06
Diluted (Note 13)			
Net Income from Continuing Operations	2.15	2.47	2.71
Net Income from Discontinued Operations	–	1.70	0.32
	2.15	**4.17**	**3.03**

Note:

1 *Reconciliation of Canadian and US GAAP Net Income*

(Cdn$ millions)	2006	2005	2004
Net Income—Canadian GAAP	601	1,140	793
Impact of US Principles, Net of Income Taxes:			
Depreciation, Depletion, Amortization and Impairment (i)	–	(29)	(42)
Stock-Based Compensation (viii); (ix)	(29)	12	36
Other (ii); (iv); (xi)	7	(13)	1
Net Income—US GAAP	**579**	**1,110**	**788**

Consolidated Balance Sheet—US GAAP
December 31, 2006 and 2005

(Cdn$ millions, except share amounts)	2006	2005
ASSETS		
Current Assets		
Cash and Cash Equivalents	101	48
Restricted Cash and Margin Deposits	197	70
Accounts Receivable (ii)	2,976	3,151
Inventories and Supplies	786	504
Deferred Income Tax Assets	479	–
Other	67	51
Total Current Assets	4,606	3,824
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $6,792 (December 31, 2005—$5,861) (iv); (vii)	11,692	9,550
Goodwill	377	364
Deferred Income Tax Assets	141	410
Deferred Charges and Other Assets (v); (vi)	263	345
TOTAL ASSETS	**17,079**	**14,493**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings	158	–
Accounts Payable and Accrued Liabilities (ii); (ix)	3,839	3,745
Accrued Interest Payable	55	55
Dividends Payable	13	13
Total Current Liabilities	4,065	3,813
Long-Term Debt (v)	4,618	3,630
Deferred Income Tax Liabilities (i) – (xi)	2,427	1,906
Asset Retirement Obligations	683	590
Deferred Credits and Other Liabilities (vi)	597	505
Non-Controlling Interests	75	88
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2006—262,513,206 shares		
2005—261,140,571 shares	821	732
Contributed Surplus	4	2
Retained Earnings (i) – (xi)	3,945	3,418
Accumulated Other Comprehensive Income (ii); (iii); (vi)	(156)	(191)
Total Shareholders' Equity	4,614	3,961
Commitments, Contingencies and Guarantees		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**17,079**	**14,493**

Consolidated Statement of Comprehensive Income—US GAAP
For the Three Years ended December 31, 2006

(Cdn$ millions)	2006	2005	2004
Net Income—US GAAP	579	1,110	788
Other Comprehensive Income, Net of Income Taxes:			
Translation Adjustment (iii)	–	(56)	(72)
Unrealized Mark-to-Market Gain (Loss) (ii)	77	(20)	11
Minimum Unfunded Pension Liability (vi)	5	(10)	(1)
Adoption of FASB Statement 158 (vi)	(47)	–	–
Comprehensive Income	**614**	**1,024**	**726**

Consolidated Statement of Accumulated Other Comprehensive Income—US GAAP
December 31, 2006 and 2005

(Cdn$ millions)	2006	2005
Translation Adjustment (iii)	(161)	(161)
Unrealized Mark-to-Market Gains (Losses) (ii)	61	(16)
Minimum Pension Liability Adjustment (vi)	–	(14)
Unamortized Defined Benefit Pension Plan Costs (vi)	(56)	–
Accumulated Other Comprehensive Income (AOCI)	**(156)**	**(191)**

Notes to the Consolidated US GAAP Financial Statements:

i. Under US GAAP, the liability method of accounting for income taxes was adopted in 1993. In Canada, the liability method was adopted in 2000. In 1997, we acquired certain oil and gas assets and the amount paid for these assets differed from the tax basis acquired. Under US principles, this difference was recorded as a deferred tax liability with an increase to PP&E rather than a charge to retained earnings. As a result, additional depreciation, depletion, amortization and impairment of $29 million was included in net income during 2005 (2004—$42 million). The difference was fully amortized during 2005.

ii. Under US GAAP, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met.

Cash flow hedges

Changes in the fair value of derivatives that are designated as cash flow hedges are recognized in net income in the same period as the hedged item. Any fair value change in a derivative before that period is recognized on the balance sheet. The effective portion of that change is recognized in other comprehensive income with any ineffectiveness recognized in net income.

Future sale of oil and gas production: At December 31, 2003, accounts payable includes a $3 million loss on forward contracts we used to hedge commodity price risk on the future sale of a portion of our production from the Aspen field. These contracts expired in March 2004. Losses ($2 million, net of income taxes), that were deferred in accumulated other comprehensive income (AOCI) at December 31, 2003, were recognized in net sales in 2004.

Future sale of gas inventory: At December 31, 2003, accounts payable includes $11 million of losses on futures and basis swap contracts we used to hedge commodity price risk on the future sale of our gas inventory. Losses of $8 million ($5 million, net of income taxes), related to the effective portion and deferred in AOCI at December 31, 2003, were recognized in marketing and other in 2004. Additionally, losses of $3 million ($2 million, net of income taxes), related to the ineffective portion, were recognized in marketing and other under US GAAP in 2003. Under Canadian GAAP, the ineffective portion was recognized in net income in 2004.

At December 31, 2004, accounts receivable includes $6 million of gains on futures contracts and swaps we used to hedge commodity price risk on the future sale of our gas inventory. Gains of $6 million ($4 million net of income taxes), related to the effective portion and deferred in AOCI at December 31, 2004, were recognized in marketing and other in 2005.

At December 31, 2005, accounts payable includes losses of $35 million on futures contracts and swaps we used to hedge commodity price risk on the future sale of our gas inventory. Losses of $24 million ($16 million, net of income taxes), related to the effective portion and deferred in AOCI at December 31, 2005, were recognized in marketing and other in 2006. The ineffective portion of the losses of $11 million ($7 million, net of income taxes) was recognized in US GAAP net income in 2005. Under Canadian GAAP, the ineffective portion was recognized in marketing and other in 2006.

At December 31, 2006, accounts receivable includes gains of $25 million on futures contracts and swaps we used to hedge commodity price risk on the future sale of our gas inventory. Gains of $23 million ($16 million, net of income taxes), related to the effective portion, have been deferred in AOCI until the underlying gas inventory is sold. These gains will be reclassified to marketing and other as the contracts settle over the next 12 months. The ineffective portion of the gains of $2 million ($2 million, net of taxes) was recognized in marketing and other in 2006.

Also included in AOCI at December 31, 2006 are gains of $65 million ($45 million, net of income taxes) related to de-designated cash flow hedges as described in Note 7(b). These gains will be reclassified to marketing and other over the next 12 months. Under Canadian GAAP, these deferred gains are included in accounts payable and accrued liabilities.

Fair value hedges

Both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. The change in fair value of both are reflected in net income. At December 31, 2006, we had no fair value hedges in place.

iii. Under US GAAP, exchange gains and losses arising from the translation of our net investment in self-sustaining foreign operations are included in comprehensive income. Additionally, exchange gains and losses, net of income taxes, from the translation of our US-dollar long-term debt designated as a hedge of our foreign net investment are included in comprehensive income. Cumulative amounts are included in AOCI in the Consolidated Balance Sheet—US GAAP.

iv. Under Canadian GAAP, we defer certain development costs and all pre-operating revenues and costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:

- operating expenses include pre-operating costs of $3 million ($2 million, net of income taxes) (2005—$10 million ($6 million net of income taxes); 2004—$9 million ($6 million, net of income taxes)); and
- PP&E is lower under US GAAP by $28 million (December 31, 2005—$25 million).

v. Under US GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred charges and other assets. Discounts of $55 million (December 31, 2005—$57 million) have been included in long-term debt.

vi. On December 31, 2006, we adopted FASB Statement No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* as described under changes in accounting policy—US GAAP. At year-end, the unfunded amount of our defined benefit pension plans was $81 million. This amount has been included in deferred credits and other liabilities and $56 million, net of income taxes, has been included in AOCI. Prior to the adoption of FAS 158 on December 31, 2006, we included our minimum unfunded pension liability in deferred credits and other liabilities and in AOCI. At December 31, 2005, $26 million was included in deferred credits and other liabilities, $4 million was included in deferred charges and other assets and $14 million, net of income taxes was included in AOCI. During the year, our minimum unfunded pension liability decreased by $5 million, net of income taxes (2005 – increased by $10 million, net of income taxes; 2004 – increased by $1 million, net of income taxes).

vii. On January 1, 2003, we adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

viii. As described in Note 12(c), our existing stock option plan was modified to a tandem option plan in 2004 to include a cash feature. Prior to the modification of our stock option plan, we accounted for stock options using the fair-value method. Following the addition of the cash feature, we account for stock options using the intrinsic-value method. As a result of the plan modification, we recognized an obligation of $85 million for our tandem options under both Canadian and US GAAP. This resulted in a one-time, non-cash expense to net income for Canadian GAAP purposes of $54 million, net of tax, in the second quarter of 2004. For US GAAP purposes, $36 million of this expense was recognized as a reduction of US GAAP retained earnings

and $18 million was recognized as an expense to our second quarter 2004 US GAAP net income. The reduction of US GAAP retained earnings was made in respect of stock options granted prior to the adoption of FAS 123 on January 1, 2003.

ix. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, effective January 1, 2006 obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. In addition, under Canadian principles as disclosed in Note 1(u), we retroactively adopted EIC–162 which requires the accelerated recognition of stock-based compensation expense for all stock-based awards made to our retired and retirement-eligible employees. However, under US GAAP, the accelerated recognition of stock-based compensation expense for such employees is only required in respect of stock-based awards granted on or after January 1, 2006. As a result:
- general and administrative expense is higher by $42 million ($29 million, net of income taxes) for the year ended December 31, 2006 (2005—lower by $17 million ($12 million, net of income taxes));
- accounts payable and accrued liabilities are higher by $25 million at December 31, 2006 (2005—lower by $17 million); and
- the impact for 2004 is not material.

x. Under US GAAP, gains and losses on the disposition of assets are included with transportation and other expense. Gains in 2006 of $4 million, 2005 of $4 million, and 2004 of $24 million were reclassified from marketing and other to transportation and other.

xi. In May 2003, the FASB issued Statement No. 150, *Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity* that requires certain financial instruments, including our preferred securities, to be valued at fair value with changes in fair value recognized through net income. The $4 million increase in fair value from January 1, 2004 to February 9, 2004 (redemption date of preferred securities) was included in net income for the year ended December 31, 2004.

Changes in Accounting Policies—US GAAP

Stock-Based Compensation

On January 1, 2006, we adopted FASB Statement 123 (revised), *Share-Based Payment* (Statement 123(R)) using the modified prospective approach and graded vesting amortization. Under Statement 123(R), our tandem options and stock appreciation rights (StARS) are considered liability-based stock compensation plans. Under the modified prospective approach, no amounts are restated in prior periods. Upon adoption of Statement 123(R), we recorded a cumulative effect of a change in accounting principle of $2 million. This amount was recorded in general and administrative expenses in our US GAAP Consolidated Statement of Income in 2006.

Prior to the adoption of Statement 123(R), we accounted for our liability-based stock compensation plans in accordance with FASB Interpretation 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans* (the intrinsic-value method). Accordingly, obligations were accrued on a graded vesting basis and represented the difference between the market value of our common shares and the exercise price of underlying options and rights. Under Statement 123(R), obligations for liability-based stock compensation plans are measured at their fair value, and are remeasured at fair value in each subsequent reporting period.

Consistent with Statement 123(R), we account for any stock options that do not include a cash feature (equity-based stock compensation plans), using the fair-value method.

The impact of adopting Statement 123(R) on our results for the year ended December 31, 2006 is as follows:

(Cdn$ millions)	Prior to Adoption of FAS 123(R)	After Adoption of FAS 123(R)	Increase/ (Decrease)
Income from Continuing Operations before Income Taxes —US GAAP	1,306	1,264	(42)
Net Income—US GAAP	608	579	(29)
Basic Earnings per Common Share—US GAAP ($/share)	2.32	2.21	(0.11)
Diluted Earnings per Common Share—US GAAP ($/share)	2.26	2.15	(0.11)

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of our stock-based compensation, with the following assumptions:

Expected Annual Dividends per Common Share ($/share)	0.20
Expected Volatility	40%
Risk-Free Interest Rate	4.3% – 4.4%
Weighted-Average Expected Life of Compensation Instruments (in years)	2.8 – 3.0

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the implied volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds. Our valuation methodology and assumptions are consistent with those previously used under FAS 123.

Stock Options

	Number (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/option)
Outstanding at December 31, 2006	15,242	35	3.2	450	33
Outstanding at December 31, 2006 and Expected to Vest	15,156	35	3.2	445	34
Exercisable at December 31, 2006	9,345	24	2.6	373	39

The total intrinsic value of stock options exercised during the year ended December 31, 2006 was $109 million (2005 – $83 million; 2004 – $60 million). As at December 31, 2006, we had $77 million of unrecognized compensation expense related to stock options which we expect to recognize over a weighted-average period of 1.5 years.

Stock Appreciation Rights

	Number (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/right)
Outstanding at December 31, 2006	6,945	42	3.5	154	29
Outstanding at December 31, 2006 and Expected to Vest	6,759	42	3.5	151	30
Exercisable at December 31, 2006	3,076	27	2.6	115	38

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2006 was $46 million (2005—$34 million; 2004—$7 million). As at December 31, 2006, we had $54 million of unrecognized compensation expense related to stock appreciation rights which we expect to recognize over a weighted-average period of 1.6 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2006, stock-based compensation expense of $252 million (2005—$490 million; 2004—$57 million) was included in general and administrative expense in the Consolidated Statement of Income—US GAAP.

For the year ended December 31, 2006, cash proceeds of $16 million were received related to the exercise of stock options (2005—$29 million; 2004—$93 million).

For the year ended December 31, 2006, cash of $119 million (2005—$74 million; 2004—$10 million) was paid upon the exercise of stock options and stock appreciation rights. The income tax benefit recorded from the exercise of stock options and stock appreciation rights was $37 million (2005—$24 million; 2004—$3 million) for the period.

Stock Based Compensation Expense for Retired and Retirement Eligible Employees

We recognize stock-based compensation expense for our retired and retirement-eligible employees over an accelerated graded vesting period in accordance with the provisions of Statement 123(R) for stock-based awards granted to employees on or after January 1, 2006. For stock-based awards granted prior to the adoption of Statement 123(R), stock-based compensation expense for our retired and retirement-eligible employees is recognized over a graded vesting period. If we applied the accelerated graded vesting provisions of Statement 123(R) to stock-based awards granted to our retired and retirement-eligible employees prior to the adoption of Statement 123(R), our stock-based compensation expense would decrease by $10 million for the year ended December 31, 2006 (2005—increase by $19 million; 2004—increase by $2 million).

Pension and Other Post-Retirement Benefits

On December 31, 2006, we adopted FASB Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* (Statement 158), which requires, among other things, the recognition of the over-funded and under-funded status of a defined benefit plan on the balance sheet as an asset or liability. The initial impact of the standard due to unrecognized prior service costs or credits and net actuarial gains or losses as well as subsequent changes in the funded status is recognized as a component of AOCI in shareholders' equity. Additional minimum pension liabilities and related intangible assets are also de-recognized upon adoption of Statement 158.

The impact of adopting Statement 158 at December 31, 2006 reduced deferred charges and other assets by $4 million, reduced deferred future income tax liabilities by $22 million, increased deferred credits and other liabilities by $65 million and decreased AOCI by $47 million. The impact considered the additional minimum pension liability at December 31, 2006 prior to the adoption of Statement 158.

New Accounting Pronouncements

In February 2006, the FASB issued Statement 155, *Accounting for Certain Hybrid Instruments*, which amends Statement 133, *Accounting for Derivative Instruments and Hedging Activities*, and Statement 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. Statement 155 permits fair value re-measurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation from its host contract in accordance with Statement 133. Statement 155 also clarifies other provisions of Statement 133 and Statement 140. This statement is effective for all financial instruments acquired or issued in fiscal years beginning after September 15, 2006. We do not expect adoption of this statement will have a material impact on our results of operations or financial position.

In July 2006, FASB issued FIN 48 *Accounting for Uncertainty in Income Taxes* with respect to FAS 109 *Accounting for Income Taxes* regarding accounting for and disclosure of uncertain tax positions. This guidance seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. Adoption of this standard is expected to increase our future income tax liabilities by no more than $30 million and decrease our retained earnings by a corresponding amount.

In September 2006, FASB issued Statement 157, *Fair Value Measurements*. Statement 157 defines fair value, establishes a framework for measuring fair value under US generally accepted accounting principles and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Quarterly Financial Data in Accordance with Canadian and US GAAP

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	2006	2005	2006	2005	2006	2005	2006	2005
Net Sales [1]	980	856	1,039	909	997	1,094	920	1,073
Income (Loss) from Continuing Operations before Income Taxes is Comprised of: [4]								
Oil and Gas [1,2]	196	247	476	193	372	330	56	319
Energy Marketing	166	30	69	54	42	(162)	139	182
Syncrude	20	19	59	59	77	78	51	50
Chemicals [3]	12	7	22	(2)	10	215	–	10
Corporate and Other	(66)	(286)	(92)	(55)	(171)	(230)	(142)	(128)
	328	**17**	**534**	**249**	**330**	**231**	**104**	**433**
Net Income (Loss) from Continuing Operations—Canadian GAAP [4]	**(83)**	**13**	**408**	**167**	**199**	**205**	**77**	**303**
US GAAP Adjustments	282	(5)	(11)	(9)	(283)	(9)	(10)	(7)
Net Income (Loss) from Continuing Operations—US GAAP	**199**	**8**	**397**	**158**	**(84)**	**196**	**67**	**296**
Net Income (Loss)—Canadian GAAP [4]	**(83)**	**31**	**408**	**197**	**199**	**609**	**77**	**303**
US GAAP Adjustments	282	(5)	(11)	(9)	(283)	(9)	(10)	(7)
Net Income (Loss)—US GAAP	**199**	**26**	**397**	**188**	**(84)**	**600**	**67**	**296**
Earnings (Loss) per Common Share from Continuing Operations ($/share)								
Canadian GAAP—Basic	(0.32)	0.06	1.56	0.64	0.76	0.79	0.29	1.16
Canadian GAAP—Diluted	(0.32)	0.06	1.53	0.63	0.74	0.77	0.29	1.13
US GAAP—Basic	0.76	0.03	1.52	0.61	(0.33)	0.75	0.26	1.13
US GAAP—Diluted	0.74	0.03	1.48	0.60	(0.33)	0.73	0.25	1.11
Earnings (Loss) per Common Share ($/share)								
Canadian GAAP—Basic	(0.32)	0.13	1.56	0.76	0.76	2.34	0.29	1.16
Canadian GAAP—Diluted	(0.32)	0.13	1.53	0.75	0.74	2.28	0.29	1.13
US GAAP—Basic	0.76	0.10	1.52	0.72	(0.33)	2.31	0.26	1.13
US GAAP—Diluted	0.74	0.10	1.48	0.71	(0.33)	2.25	0.25	1.11
Dividends Declared [5]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Common Share Prices ($/share)								
Toronto Stock Exchange—High	68.10	35.50	69.50	39.85	71.22	60.67	65.79	59.54
Toronto Stock Exchange—Low	54.34	23.55	50.82	29.53	52.13	40.25	52.91	43.77
New York Stock Exchange—High (US$)	59.94	29.18	61.68	32.32	63.65	51.73	58.37	51.69
New York Stock Exchange—Low (US$)	46.98	19.44	45.63	23.28	46.70	31.95	46.90	36.80

Notes:

1 *Excludes results of Canadian conventional oil and gas properties sold in the third quarter of 2005 in southeast Saskatchewan, northwest Saskatchewan, northeast British Columbia and the Alberta foothills. These results are shown as discontinued operations (see Note 14 to the Consolidated Financial Statements).*

2 *The fourth quarter of 2006 includes an impairment charge of $93 million, primarily relating to two natural gas properties in the Gulf of Mexico.*

3 *Chemicals operating profit includes a dilution gain of $193 million in the third quarter of 2005 as the result of the Canexus initial public offering.*

4 *Includes the impact of changes in accounting policies as described in Note 1(u) to the Consolidated Financial Statements.*

5 *In February 2007, the Board of Directors declared a quarterly dividend of $0.05 per common share, payable April 1, 2007, to shareholders of record on March 10, 2007.*

6 *At December 31, 2006, there were 1,454 registered holders of common shares and 262,513,206 common shares outstanding.*

OIL AND GAS PRODUCING ACTIVITIES AND SYNCRUDE OPERATIONS (UNAUDITED)

The following oil and gas information is provided in accordance with the FASB Statement No. 69 *Disclosures about Oil and Gas Producing Activities*. It also includes information relating to our interest in Syncrude as it produces a crude oil product similar to our oil and gas activities even though these operations are considered mining activities under SEC regulations.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves for our conventional operations (excluding Syncrude) are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the reserves (including Syncrude) have been assessed by independent qualified reserves consultants.

Estimates of crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. See Critical Accounting Estimates in Item 7 for a description of our reserves estimation process.

	Total		Yemen [1]	Canada			United States		United Kingdom		Other Countries [3]
Conventional oil and bitumen are in mmbbls and natural gas is in bcf	Oil	Gas	Oil	Oil	Gas	Bitumen [2]	Oil	Gas	Oil	Gas	Oil
Proved Developed and Undeveloped Reserves [4]											
December 31, 2003	**289**	**661**	**110**	**97**	**405**	**4**	**67**	**256**	**–**	**–**	**11**
Extensions and Discoveries	244	33	1	3	18	239	1	15	–	–	–
Purchases of Reserves in Place	127	23	–	1	–	–	–	–	126	23	–
Sales of Reserves in Place	(1)	(3)	–	(1)	(2)	–	–	(1)	–	–	–
Revisions of Previous Estimates	(265)	(25)	(12)	(11)	(7)	(243)	(6)	(9)	3	(9)	4
Production	(43)	(89)	(19)	(10)	(42)	–	(10)	(46)	(1)	(1)	(3)
December 31, 2004	**351**	**600**	**80**	**79**	**372**	**–**	**52**	**215**	**128**	**13**	**12**
Extensions and Discoveries	15	111	5	4	47	–	1	57	5	7	–
Purchases of Reserves in Place	2	–	–	2	–	–	–	–	–	–	–
Sales of Reserves in Place	(28)	(80)	–	(28)	(80)	–	–	–	–	–	–
Revisions of Previous Estimates	9	(18)	(3)	2	3	–	(5)	(21)	15	–	–
Production	(45)	(81)	(23)	(9)	(37)	–	(7)	(36)	(5)	(8)	(1)
December 31, 2005	**304**	**532**	**59**	**50**	**305**	**–**	**41**	**215**	**143**	**12**	**11**
Extensions and Discoveries	52	89	1	1	54	–	2	26	23	9	25
Purchases of Reserves in Place	–	1	–	–	1	–	–	–	–	–	–
Sales of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Revisions of Previous Estimates	231	(16)	(3)	3	(13)	219	(8)	(12)	19	9	1
Production	(38)	(74)	(19)	(6)	(33)	–	(5)	(34)	(6)	(7)	(2)
December 31, 2006	**549**	**532**	**38**	**48**	**314**	**219**	**30**	**195**	**179**	**23**	**35**
Proved Developed Reserves [5]											
December 31, 2004	199	518	49	72	348	–	48	166	20	4	10
December 31, 2005	154	438	46	44	275	–	37	161	17	2	10
December 31, 2006	**286**	**460**	**33**	**44**	**287**	**40**	**28**	**161**	**131**	**12**	**10**

Notes:

1. *Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.*
2. *Represents bitumen reserves from the insitu recovery of Canadian oil sands, rather than upgraded synthetic crude oil reserves to be sold.*
3. *Represents reserves in Nigeria and Colombia.*
4. *Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.*
5. *Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.*

Our net proved reserves and changes in those reserves for our Syncrude operations are disclosed below. Additional disclosures required by SEC Industry Guide 7 are on pages 22 and 23. The net proved reserves represent management's best estimate of proved synthetic reserves after royalties.

Estimates of Syncrude's synthetic crude oil reserves are based on detailed geological and engineering assessments of the bitumen volume in-place, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. In accordance with the approved mining plan, there are an estimated 1,780 million tons of economically extractable oil sands in the Base and North Mines, with an average bitumen grade of 10.6 weight percent. The Aurora North Mine contains an estimated 4,810 million tons of economically extractable oil sands at an average bitumen grade of 11.2 weight percent. Aurora South Lease 31 contains measured economically extractable oil sands of 4,309 million tons at an average bitumen grade of 10.8 weight percent.

	Synthetic Crude Oil		
(millions of barrels)	**Base Mine and North Mine [1]**	**Aurora [2]**	**Total**
December 31, 2003	**55**	**193**	**248**
Revision of Previous Estimates	(1)	(5)	(6)
Extensions and Discoveries	–	19	19
Production	(4)	(2)	(6)
December 31, 2004	**50**	**205**	**255**
Revision of Previous Estimates	–	(4)	(4)
Extensions and Discoveries	–	19	19
Production	(3)	(3)	(6)
December 31, 2005	**47**	**217**	**264**
Revision of Previous Estimates	1	4	5
Extensions and Discoveries	–	11	11
Production	(3)	(3)	(6)
December 31, 2006	**45**	**229**	**274**

Notes:

1 Leases 17 and 22

2 Leases 10, 12, 31 and 34.

B. Capitalized Costs (excluding Syncrude operations)

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
December 31, 2006				
Yemen	2,404	–	(2,128)	276
Canada	3,787	227	(1,467)	2,547
United States	2,768	121	(1,445)	1,444
United Kingdom	4,325	385	(432)	4,278
Other Countries	99	150	(78)	171
Total Capitalized Costs	**13,383**	**883**	**(5,550)**	**8,716**
December 31, 2005				
Yemen	2,243	–	(1,841)	402
Canada	3,463	143	(1,330)	2,276
United States	2,323	114	(1,159)	1,278
United Kingdom	3,603	410	(216)	3,797
Other Countries	88	161	(119)	130
Total Capitalized Costs	**11,720**	**828**	**(4,665)**	**7,883**
December 31, 2004				
Yemen	2,022	16	(1,550)	488
Canada	3,732	136	(2,025)	1,843
United States	2,102	147	(1,037)	1,212
United Kingdom	3,117	382	(16)	3,483
Other Countries	437	98	(408)	127
Total Capitalized Costs	**11,410**	**779**	**(5,036)**	**7,153**

C. Costs Incurred (excluding Syncrude operations)

		Oil and Gas				
(Cdn$ millions)	Total Oil and Gas	Yemen	Canada	United States	United Kingdom	Other
Year Ended December 31, 2006						
Property Acquisition Costs						
Proved	13	–	12	–	1	–
Unproved	125	–	105	19	1	–
Exploration Costs	514	37	74	242	71	90
Development Costs	2,051	145	884	399	595	28
Asset Retirement Costs	69	4	5	4	56	–
Total Costs Incurred	**2,772**	**186**	**1,080**	**664**	**724**	**118**
Year Ended December 31, 2005						
Property Acquisition Costs						
Proved	20	–	17	3	–	–
Unproved	15	–	–	9	6	–
Exploration Costs	509	44	97	235	61	72
Development Costs	1,896	236	947	139	560	14
Asset Retirement Costs	196	13	58	45	80	–
Total Costs Incurred	**2,636**	**293**	**1,119**	**431**	**707**	**86**
Year Ended December 31, 2004						
Property Acquisition Costs						
Proved	1,774	–	4	–	1,770	–
Unproved	1,491	–	–	–	1,491	–
Exploration Costs	339	22	56	162	4	95
Development Costs	1,102	267	491	267	53	24
Asset Retirement Costs	168	3	27	4	134	–
Total Costs Incurred	**4,874**	**292**	**578**	**433**	**3,452**	**119**

D. Results of Operations for Producing Activities (excluding Syncrude operations)

(Cdn$ millions)	Total Oil and Gas	Oil and Gas: Yemen	Canada [1]	United States	United Kingdom	Other Countries [1]
Year Ended December 31, 2006						
Net Sales	3,032	1,328	459	629	477	139
Production Costs	491	151	146	106	80	8
Exploration Expense	362	4	26	214	46	72
Depreciation, Depletion, Amortization and Impairment	1,011	327	162	296	216	10
Other Expenses (Income)	71	15	106	(23)	(71)	44
	1,097	831	19	36	206	5
Income Tax Provision	687	289	6	13	378	1
Results of Operations	**410**	**542**	**13**	**23**	**(172)**	**4**
Year Ended December 31, 2005						
Net Sales	3,263	1,377	609	792	366	119
Production Costs	511	150	158	96	95	12
Exploration Expense	251	12	24	100	51	64
Depreciation, Depletion, Amortization and Impairment	1,008	354	197	234	210	13
Other Expenses (Income)	335	40	125	83	(8)	95
	1,158	821	105	279	18	(65)
Income Tax Provision (Recovery)	411	285	32	99	7	(12)
Results of Operations	**747**	**536**	**73**	**180**	**11**	**(53)**
Year Ended December 31, 2004						
Net Sales	2,538	921	622	811	36	148
Production Costs	437	109	156	106	6	60
Exploration Expense	246	2	21	138	3	82
Depreciation, Depletion, Amortization and Impairment	712	169	240	258	18	27
Other Expenses	106	4	38	19	–	45
	1,037	637	167	290	9	(66)
Income Tax Provision	406	222	75	104	4	1
Results of Operations	**631**	**415**	**92**	**186**	**5**	**(67)**

Note:
1 2005 and 2004 include results of discontinued operations (see Note 14).

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein (excluding Syncrude operations)

The following disclosure is based on estimates of net proved reserves (excluding Syncrude) and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved oil and gas reserves (excluding Syncrude operations). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	United Kingdom	Other Countries
December 31, 2006						
Future Cash Inflows	32,247	2,330	12,678	3,151	11,437	2,651
Future Production Costs	9,523	606	5,615	791	2,236	275
Future Development Costs	3,190	115	1,156	332	891	696
Future Dismantlement and Site Restoration Costs, Net	1,006	11	289	197	471	38
Future Income Tax	5,204	489	753	450	3,308	204
Future Net Cash Flows	13,324	1,109	4,865	1,381	4,531	1,438
10% Discount Factor	4,951	106	2,484	321	970	1,070
Standardized Measure	**8,373**	**1,003**	**2,381**	**1,060**	**3,561**	**368**
December 31, 2005						
Future Cash Inflows	23,040	3,675	4,558	5,002	9,190	615
Future Production Costs	5,477	807	1,886	811	1,892	81
Future Development Costs	1,093	153	124	268	534	14
Future Dismantlement and Site Restoration Costs, Net	778	20	180	193	381	4
Future Income Tax	4,496	795	244	1,107	2,172	178
Future Net Cash Flows	11,196	1,900	2,124	2,623	4,211	338
10% Discount Factor	3,154	338	811	697	1,209	99
Standardized Measure	**8,042**	**1,562**	**1,313**	**1,926**	**3,002**	**239**
December 31, 2004						
Future Cash Inflows	18,950	3,779	4,747	4,085	5,852	487
Future Production Costs	4,781	722	2,135	613	1,271	40
Future Development Costs	1,477	275	100	185	903	14
Future Dismantlement and Site Restoration Costs, Net	626	4	149	129	336	8
Future Income Tax	2,798	388	382	845	1,058	125
Future Net Cash Flows	9,268	2,390	1,981	2,313	2,284	300
10% Discount Factor	2,978	499	760	631	1,011	77
Standardized Measure	**6,290**	**1,891**	**1,221**	**1,682**	**1,273**	**223**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	2006	2005	2004
Beginning of Year	8,042	6,290	5,517
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(2,291)	(2,028)	(1,674)
Net Changes in Prices and Production Costs Related to Future Production	(1,065)	3,302	142
Extensions, Discoveries and Improved Recovery, Less Related Costs [1]	695	977	(71)
Changes in Estimated Future Development and Dismantlement Costs	(692)	(135)	(122)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	1,048	638	604
Revisions of Previous Quantity Estimates	1,936	478	(223)
Accretion of Discount	1,117	799	692
Purchases of Reserves in Place	2	15	1,764
Sales of Reserves in Place	(2)	(882)	(20)
Net Change in Income Taxes	(417)	(1,412)	(319)
End of Year	**8,373**	**8,042**	**6,290**

Note:

1 2004 includes approximately $230 million of negative discounted future net cash flows relating to bitumen reserves based on year-end assumptions.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There were no disagreements with accountants on accounting and financial disclosure.

ITEM 9A. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-d-15(e)) as of the end of the period covered by this report. They concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Company and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2006. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006, has been audited by Deloitte & Touche LLP, independent registered Chartered Accountants, as stated in their report which is on page 138 of this Form 10-K. Deloitte & Touche LLP also audited our Consolidated Financial Statements as stated in their report which is on page 86 of this Form 10-K.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems relative to internal control over financial reporting. In 2006, we implemented our existing Systems, Applications, and Products in Data Processing (SAP) into our UK operations and, in keeping pace with growth in our US operations, we implemented additional inventory tracking and procure to pay process controls. The conversion of data and the implementation and operation of SAP has been continually monitored and reviewed.

We have evaluated these changes and confirm that there have been no other changes in our internal control over financial reporting during the fourth quarter of 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on these evaluations, there were no material weaknesses in these internal controls requiring corrective action. As a result, no such corrective action was taken.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Nexen Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2006, and our report dated February 9, 2007, expressed an unqualified opinion on those financial statements and included a separate report on Canada-United States of America reporting differences.

Calgary, Canada
February 9, 2007

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

Corporate Governance

Governance is a two way street. Our board and management are committed to transparent, meaningful disclosure and to feedback from stakeholders for continuous improvement.

PARTS III AND IV

ITEMS 10 TO 15.

PART III

ITEMS 10 AND 11. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE, AND EXECUTIVE COMPENSATION

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On July 5 2006, the board determined that, until changed, there will be 12 directors.

Our By-Laws provide that directors will be elected at the annual general meeting of shareowners (AGM) each year and will hold office until their successors are elected. All of our current directors were elected at the last AGM with the exception of A. Anne McLellan PC, who was appointed on July 5, 2006.

This table shows our directors' principal occupations or employment during the past five years and any other directorships they held in public companies as at February 15, 2007. The following directors are management nominees for election to the board.

Name (Age)	**Principal Occupation**	**Other Directorships**	**Nexen Director Since**
Charles W. Fischer (56)	President and Chief Executive Officer (CEO) of Nexen.		2000
Dennis G. Flanagan [1,2,3] (67)	Retired oil executive.	Canexus Income Fund (Chair) NAL Oil & Gas Trust	2000
David A. Hentschel [4] (73)	Retired oil executive. Formerly: Oil and gas consultant.	Cimarex Energy Co.	1985
S. Barry Jackson [1] (54)	Retired oil executive. Formerly: Chair of Resolute Energy Inc. and Chair of Deer Creek Energy Limited.	Cordero Energy Inc. TransCanada Corporation (Chair) TransCanada PipeLines Limited (Chair)	2001
Kevin J. Jenkins [1,2] (50)	Managing Director of TriWest Capital Partners Formerly: President and CEO of The Westaim Corporation.		1996
A. Anne McLellan, P.C. [1] (56)	Counsel at Bennett Jones LLP, Barristers and Solicitors and Distinguished Scholar in Residence at the University of Alberta in the Institute for United States Policy Studies Formerly: Liberal Member of Parliament for Edmonton Centre, Deputy Prime Minister, Minister of Public Safety and Emergency Preparedness and Minister of Health	Agrium Inc. Cameco Corporation	2006
Eric P. Newell, O.C. (62)	Retired Chair and CEO of Syncrude Canada Ltd.	Canfor Corporation	2004
Thomas C. O'Neill [1,2] (61)	Retired Chair of PwC Consulting. Formerly: CEO of PwC Consulting. Prior to that, COO of PricewaterhouseCoopers LLP, Global.	Adecco S.A. BCE Inc. Loblaw Companies Limited	2002
Francis M. Saville, Q.C. [1] (68)	Chair of Nexen. Counsel to Fraser Milner Casgrain LLP, Barristers and Solicitors. Formerly: Senior Partner and Vice Chair of Fraser Milner Casgrain LLP, Barristers and Solicitors.		1994
Richard M. Thomson, O.C. [1,2] (73)	Retired banking executive.	The Thomson Corporation	1997
John M. Willson [1] (67)	Retired mining executive.	Aber Diamond Corporation Finning International Inc. Pan American Silver Corporation	1996
Victor J. Zaleschuk [5] (63)	Retired oil executive.	Agrium Inc. Cameco Corporation (Chair)	1997

Notes:

1 *All members of the Audit and Conduct Review (Audit), Corporate Governance and Nominating (Governance) and Compensation and Human Resources (Compensation) Committees are independent. All members of the Audit Committee are independent under additional regulations for audit committee members.*

2 *Financial Experts on Nexen's Audit Committee.*

3 *Mr. Flanagan was a director of Elek-Tek Inc., a US public computer retailing company, that was subject to bankruptcy proceedings in 1998.*

4 *Mr. Hentschel was Chair and CEO of Occidental Oil and Gas Corporation from 1997 to 1999 and President and CEO of Nexen from 1995 to 1997.*

5 *Mr. Zaleschuk was President and CEO of Nexen from 1997 to 2001.*

Independence and Board Committees

The board affirmed director independence in reference to our categorical standards, which are available at www.nexeninc.com, in place since 2003 and most recently confirmed on February 15, 2007. Our categorical standards meet or exceed the requirements set out in SEC rules and regulations, the *Sarbanes-Oxley Act of 2002* (Sarbanes-Oxley), the NYSE rules, *National Policy 58-201 — Corporate Governance Guidelines*, *Multilateral Instrument 52-110 — Audit Committees,* and applicable provisions of *National Instrument 51-101 — Standards of Disclosure for Oil and Gas Activities*.

Mr. Fischer is not independent as he is President and CEO.

Mr. Saville, a director, was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta until the end of January 2004. Since February 1, 2004, he has been counsel with the firm. FMC provided legal services to us during each of the last five years. Mr. Saville neither solicits nor participates in those services and does not receive any portion of the fees we pay to FMC. He is an independent director pursuant to our categorical standards.

Ms. McLellan, a director, has been counsel with Bennett Jones LLP (BJ), Barristers and Solicitors, Edmonton, Alberta, since June 27, 2006. BJ provided legal services to us during each of the last five years. Ms. McLellan neither solicits nor participates in those services and does not receive any portion of the fees we pay to BJ. She is an independent director pursuant to our categorical standards.

	Committees (Number of Members)					
	Audit [1,2]	**Compensation** [1,3]	**Governance** [1]	**Finance**	**Reserves** [4]	**SESR**
	(6)	(7)	(7)	(7)	(7)	(7)
Independent Outside Directors						
Dennis G. Flanagan [5]	√		√	√	√	
David A. Hentschel				√	√	√
S. Barry Jackson	√	√			√	Chair
Kevin J. Jenkins [5]	√	Chair	√			√
A. Anne McLellan, P.C.		√	√	√		√
Eric P. Newell, O.C.				√	√	√
Thomas C. O'Neill [5,6]	Chair	√	√		√	
Francis M. Saville, Q.C.		√	√	√		√
Richard M. Thomson, O.C. [5]	√	√	Chair	√		
John M. Willson	√	√	√		Chair	
Victor J. Zaleschuk				Chair	√	√
Management Director — Not Independent						
Charles W. Fischer						

Notes:

1 *All members of the Audit and Conduct Review (Audit), Corporate Governance and Nominating (Governance) and Compensation and Human Resources (Compensation) Committees are independent. All members of the Audit Committee are independent under additional regulations for audit committee members.*

2 *Experience of the members of the Audit Committee that indicates an understanding of the accounting principles we use to prepare our financial statements is shown in their biographies on page 143.*

3 *Composition of the Compensation Committee has changed since January 1, 2006. See page 146 for details.*

4 *A majority of the Reserves Review (Reserves) Committee are independent.*

5 *Audit committee financial expert under US regulatory requirements.*

6 *The board has considered the circumstances of Mr. O'Neill's service on four public company audit committees including Nexen's. Mr. O'Neill is retired and holds neither a full nor a part-time employee position. His only commitments are to the boards and committees on which he serves. Mr. O'Neill has been a chartered accountant for more than 30 years, having joined the audit firm of Price Waterhouse (now part of PricewaterhouseCoopers LLP) in 1967. Accordingly, the board has determined that service as an audit committee member on three other public companies does not impair Mr. O'Neill's ability to serve on our Audit Committee.*

Audit Committee Financial Expert Experience

Name	Experience
Flanagan	Dennis Flanagan, 67, is a retired oil executive. He worked in the oil and gas industry for more than 40 years with Ranger Oil Limited (Ranger) and ELAN Energy Inc. (ELAN), most recently as Executive Chair of ELAN until it was bought by Ranger in 1997. He was involved in all phases of exploration and development in Canada, the US and the UK sector of the North Sea. Mr. Flanagan completed the Registered Industrial and Cost Accountant program, the predecessor to the Certified Management Accountant program, in 1967. He worked in various accounting and management positions at Ranger, including the position of chief financial officer. Dennis is the Chair of Canexus Income Fund (Canexus), an affiliate controlled by Nexen, and a director of NAL Oil & Gas Trust. He is also founding Chair of STARS (Shock Trauma Air Rescue) Foundation.
Jenkins	Kevin Jenkins, 50, is Managing Director of TriWest Capital Partners, an independent private equity firm. He was President, CEO and a director of The Westaim Corporation from 1996 to 2003, with businesses including technology investments, production of coin blanks, aerospace coatings and surface engineered products. From 1985 to 1996 he held senior executive positions with Canadian Airlines International Ltd. (Canadian). He was elected to serve on Canadian's board of directors in 1987, appointed President in 1991 and appointed President and CEO in 1994. Mr. Jenkins has a Bachelors Degree in Law from the University of Alberta and a Masters of Business Administration from Harvard Business School. He has worked in management positions with increasing level of responsibility including assistant treasurer, vice president finance, executive vice president and chief financial officer, and president and CEO. Kevin is Chair of Young Life of Canada and a member of the board of World Vision Canada.
O'Neill	Tom O'Neill, 61, is the retired Chair of PwC Consulting. He was formerly CEO of PwC Consulting, COO of PricewaterhouseCoopers LLP, Global, CEO of PricewaterhouseCoopers LLP, Canada and Chair and CEO of Price Waterhouse Canada. He worked in Brussels in 1975 to broaden his international experience and from 1975 to 1985 was client service partner for numerous multi nationals, specializing in dual Canadian and US listed companies. Mr. O'Neill has a Bachelor of Commerce Degree from Queen's University. He received his Chartered Accountant designation in 1970 and was made a Fellow (FCA) of the Institute of Chartered Accountants of Ontario in 1988. He also has an Honourary Doctorate of Law from Queen's University. Tom is a director of BCE Inc., Loblaw Companies Limited, Adecco S.A., and Ontario Teachers' Pension Plan Board. He is also Vice Chair of the Board of Governors of Queen's University and a director of St. Michael's Hospital.
Thomson	Dick Thomson, 73, is a retired banking executive. He was with the Toronto Dominion Bank, one of Canada's largest banks, since 1957, as President from 1972 to 1978 and as Chair from 1978 until his retirement in 1998. Mr. Thomson holds a Masters of Business Administration from Harvard Business School and a Bachelor of Arts and Science in Engineering from the University of Toronto. He is an Officer of the Order of Canada. Dick is a director of The Thomson Corporation. He is also a member of the board of the Multiple Sclerosis Scientific Research Foundation.

Directors' and Officers' Liability Insurance

We maintain a directors' and officers' liability insurance policy. The policy provides coverage for costs incurred to defend and settle claims against directors and officers of Nexen to an annual limit of US$130 million with a US$12.5 million deductible per occurrence. The cost of coverage for 2006 was approximately US$0.9 million. Directors and officers do not pay any portion of the premiums and no indemnity claims were made or became payable in 2006.

Directors' and Officers' Fiduciary Insurance

We also maintain a fiduciary liability insurance policy. The policy provides coverage for costs incurred to defend and settle claims against Nexen, our directors, officers and employees for breach of fiduciary duty in connection with company sponsored plans, such as pension and savings plans. This policy has an annual limit of US$25 million with a US$2.5 million deductible for an indemnifiable occurrence and no deductible for a non-indemnifiable occurrence. The cost of coverage for 2006 was approximately US$30,000. Directors and officers do not pay any portion of the premiums and no claims were made or became payable in 2006.

Loans to Directors

As set out in the corporate governance policy, we do not make loans to our directors. There are no loans outstanding from Nexen to any of our directors.

DIRECTOR COMPENSATION

Director compensation includes annual retainers, meeting fees and equity-based incentive compensation in the form of deferred share units (DSUs). The compensation is intended to provide an appropriate level of remuneration considering the responsibilities, time requirements and accountability of their roles. All elements of director compensation are reviewed annually for competitiveness against a peer group of oil and gas companies by management, and then the board.

In 2003, the board adopted a policy stating that non-executive directors would no longer be granted stock options. We do not provide our directors with any form of non-equity incentive or pension compensation.

There are currently two directors, Mr. Hentschel and Mr. Zaleschuk, both former CEO's of Nexen, who are retirees in the Nexen pension plan. The pension benefit provided to these directors is for previous service as employees.

A DSU plan was approved for the non-executive directors in 2001, as an appropriate form of equity-based compensation intended to provide a competitive long-term incentive aligned with shareowner interests.

In December 2006, all director compensation was reviewed and confirmed at the then-current levels.

Director Summary Compensation Table

Name	Total Fees Earned [1]	DSU Awards [2]	All Other Compensation [3]	Total Compensation
Fischer [4]	–	–	–	–
Flanagan [5]	116,667	132,720	115,331	364,718
Hentschel	101,633	132,720	2,726	237,079
Jackson	116,600	132,720	2,953	252,273
Jenkins	120,200	132,720	4,411	257,331
McLellan	62,850	132,720	259	195,829
Newell	91,400	132,720	4,291	228,411
O'Neill	132,800	132,720	4,018	269,538
Saville	263,100	202,240	3,116	468,456
Thomson	120,200	132,720	5,946	258,866
Willson	116,600	132,720	4,308	253,628
Zaleschuk	103,367	132,720	2,819	238,906
Total	**$1,345,417**	**$1,529,440**	**$150,178**	**$3,025,035**

Notes:

1 *Includes all retainers and meetings fees, including fees paid in the form of DSUs.*

2 *The value of DSUs granted on December 4, 2006, based on the closing market price of Nexen common shares on the TSX on December 1, 2006 of $63.20.*

3 *The total value of perquisites provided to each director is less than both $50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2006 valued at the closing market price of Nexen common shares on the TSX on the payment dates, and Canexus fees as set out in note 5.*

4 *As an executive officer of Nexen, Mr. Fischer is not paid director fees.*

5 *Mr. Flanagan is the Board Chair of Canexus and was paid fees of $59,000 in 2006, received deferred trust units of Canexus valued at $48,770 and distributions on his trust units of $4,806. This amount is included in "All Other Compensation"*

Director Fees

Annual board and committee retainers are paid quarterly, in advance, and are pro-rated for partial service, if appropriate. Nexen also reimburses directors for out-of-pocket travel expenses. Directors are paid meeting fees for attending meetings either in person or by telephone conference call. From January 1, 2006, non-executive directors are paid:

Annual Board Chair Retainer [1]	$150,000
Annual Board Retainer	28,100
Annual Committee Retainer (per committee)	9,100
Annual Committee Additional Chair Retainer	5,300
Annual Audit Committee Additional Chair Retainer [2]	14,400
Board and Committee Meeting Fees (per meeting attended)	1,800

Notes:

1 *The total annual retainer paid to the Board Chair is $178,100 and includes the Annual Board Chair Retainer and the Annual Board Retainer.*

2 *The total annual retainer paid to the Chair of the Audit Committee for his service on that committee is $28,800 and includes the Annual Committee Retainer, the Annual Committee Additional Chair Retainer and the Annual Audit Committee Additional Chair Retainer.*

2006 Retainers and Fees

	Annual Board Retainer	Annual Committee Retainers	Annual Committee Chair Retainer	Board Meeting Fees	Committee Meeting Fees	Total Fees Earned	Total Fees Credited in DSUs	Total Fees Earned in Cash
Fischer [1]	–	–	–	–	–	–	–	–
Flanagan	28,100	36,400	1,767	14,400	36,000	116,667	–	116,667
Hentschel	28,100	30,333	–	14,400	28,800	101,633	–	101,633
Jackson	28,100	36,400	5,300	14,400	32,400	116,600	116,600	–
Jenkins	28,100	36,400	5,300	14,400	36,000	120,200	–	120,200
McLellan [2]	14,050	18,200	–	9,000	21,600	62,850	62,850	–
Newell	28,100	27,300	–	12,600	23,400	91,400	91,400	–
O'Neill	28,100	36,400	19,700	12,600	36,000	132,800	–	132,800
Saville	178,100	36,400	–	14,400	34,200	263,100	–	263,100
Thomson	28,100	36,400	5,300	14,400	36,000	120,200	120,200	–
Willson	28,100	36,400	5,300	14,400	32,400	116,600	–	116,600
Zaleschuk	28,100	30,334	3,533	14,400	27,000	103,367	28,100	75,267
Total	**$445,050**	**$360,967**	**$46,200**	**$149,400**	**$343,800**	**$1,345,417**	**$419,150**	**$926,267**

Notes:

1 *As an executive officer of Nexen, Mr. Fischer is not paid director fees.*

2 *Ms. McLellan is taking all fees in Deferred Share Units (DSUs) until her share ownership requirement is met.*

Share Ownership Guideline

The board believes it is important that directors demonstrate their commitment to Nexen's growth through share ownership. The board-approved guideline sets out that directors are expected to own or control at least 6,000 shares (DSUs count towards share ownership) to be accumulated over three years. Specific arrangements may be made when a qualified candidate might be prevented from serving by this guideline. The guideline is reviewed from time to time. Ownership can be achieved by purchasing common shares, participating in our dividend reinvestment plan or directing retainer fees into DSUs.

All directors, except Ms. McLellan, meet the guideline. Ms. McLellan has until July 5, 2009 to meet this guideline. She is taking 100% of her fees in DSUs until she meets the requirement and currently has 4,341 DSUs that count toward her requirement.

Deferred Share Units

In 2001, a DSU plan was approved as an alternative form of compensation for non-executive directors. Under the plan, eligible directors may elect annually to receive all or part of their fees in DSUs, rather than in cash. A DSU is a bookkeeping entry that tracks the value of one Nexen common share. When cash dividends are paid on Nexen common shares, eligible directors are credited with additional DSUs. The number of DSUs is calculated by dividing the total amount of the dividends that would have been paid if the DSUs in the director's account were common shares by the fair market value of a common share on the payment date. DSUs accumulate over a director's term of service and are not paid out until the director leaves the board, providing them with an ongoing stake in Nexen during the term of service. When the director leaves the board, payments may be made in cash or in Nexen common shares purchased on the open market, at Nexen's option.

Grants of DSUs have been used since 2003 as equity-based compensation in place of stock option grants, which were discontinued for non-executive directors in 2003.

Deferred Share Units Granted in 2006

	Grant Date	DSUs	Base Price [1]	Value of DSUs [2]
		(#)	($)	($)
Board Chair	Dec 4, 2006	3,200	63.20	202,240
Other Non-Executive Directors	Dec 4, 2006	2,100	63.20	132,720

Notes:
1 *The closing market price of Nexen common shares on the TSX on December 1, 2006.*
2 *The number of DSUs times the base price.*

TOPs Exercised or Exchanged and Awards Vested During 2006

All exercise or exchange activity in 2006 occurred within five months of the expiry date of the options. There are no vesting provisions and, accordingly, no value realized on vesting under the DSU plan.

	TOPs Awards		Stock Awards	
Name	Exercised or Exchanged	Value Realized [1]	Shares Acquired on Vesting	Value Realized
	(#)	($)	(#)	($)
Hentschel	13,000	579,215	–	–
Jackson	13,000	566,345	–	–
Thomson	19,600	1,044,974	–	–
Zaleschuk	24,000	1,255,740	–	–

Note:
1 *Equals market price at the time of the exercise or exchange, minus the exercise price, as defined in the Tandem Option (TOPs) plan.*

COMPENSATION COMMITTEE REPORT

The Compensation Committee assists the board in overseeing key compensation and human resources policies, CEO and executive management compensation, and executive management succession and development. The Committee reports to the board, as set out in its mandate, and the board or independent directors give final approval to compensation matters.

Changes to Committee Membership in 2006

Messrs. Jenkins and O'Neill joined the Committee and Messrs. Hentschel and Zaleschuk left the Committee on April 27, 2006. That same date, Mr. Jenkins was appointed Committee Chair to replace Mr. Willson. Ms. McLellan joined the Committee on July 5, 2006.

Key Activities in 2006

- Recommended programs for employee, executive and CEO compensation, including base salary, annual cash incentive and long-term incentive programs (TOPs and STARs);
- Oversaw payments and grants made under Nexen's annual cash incentive, TOPs and STARs plans;
- Recommended to the board salaries, bonuses and grants of TOPs to executive officers;
- Evaluated CEO performance on short-term and long-term corporate goals and objectives, and recommended his compensation, which was approved by the independent directors of the board;
- Reviewed the CEO's position description; and
- Recommended compensation programs in the form of retention or recognition awards for key business initiatives.

Independent Consultant

The Committee engaged Mercer Human Resource Consulting (Mercer) to provide a report of confidential market data on the CEO's compensation, and a technical analysis of the market data in light of our compensation plans and practices. The report includes competitive compensation data from a list of peer companies, which is recommended by the independent consultant and approved by the Committee. The decisions of the Committee are their responsibility and may reflect factors other than the information and recommendations provided by Mercer.

Mercer also provided limited general employee compensation consulting services to Nexen in 2006. Specifically, Mercer provided administrative services to management related to international pension arrangements. We also participated in compensation surveys in Canada and international locations and purchased some of the published results. Management would obtain Committee approval before retaining Mercer for compensation consulting work.

Fees Billed by Independent Consultant

Type of Fee	Billed in 2006	Percentage of Total Fees billed in 2006
For independent assessment of CEO compensation for the Committee	37,780	92%
For administrative services provided to management	3,470	8%
Total Annual Fees	$41,250	100%

External Recognition and Verification

Nexen was recognized for our human resource practices during 2006, including the following:

- Named one of the 50 Best Employers in Canada by Hewitt Associates Inc.; and
- Named one of Alberta's Top 25 Employers by Mediacorp Canada Inc.

Committee Approval

The Committee has reviewed and discussed the compensation disclosure included in this document, including the information on pages 144 through 164, and has recommended to the board that it be included in the Form 10-K.

Submitted on behalf of the Compensation Committee:

Kevin Jenkins, Chair
Barry Jackson
Anne McLellan
Tom O'Neill
Francis Saville
Dick Thomson
John Willson

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation Committee are set out on page 142. Mr. Saville had a relationship requiring disclosure, the details of which are set out under "Certain Relationships and Related Transactions, and Director Independence" on page 170. There are no Compensation Committee interlocks during 2006.

COMPENSATION DISCLOSURE

We are committed to best practices in corporate governance, disclosure and transparency. This discussion of compensation practices at Nexen is intended to provide a clear understanding of our compensation objectives and programs. For 2006, we are providing compensation disclosure that will comply with the requirements of the Canadian Securities Administrators. As a foreign private issuer in the US, we are not required to disclose compensation in accordance with the SEC rules issued in 2006. We have, however, complied with the spirit of those rules where possible, without compromising required Canadian disclosure.

Executive Compensation Philosophy

Nexen's policies and practices for executive compensation are linked to its strategic business objectives, including increasing shareowner returns. Within that framework, the overall philosophy is to compensate executives based on performance, at a level competitive with our peers, and in a manner designed to attract and retain a talented leadership team focused on managing Nexen's operations, finances and assets.

Our compensation programs are designed to meet performance and competitiveness objectives. To ensure pay-for-performance, rewards are directly linked to planned performance for Nexen and its divisions. Individual performance and contribution are considered in determining awards. Measures are aligned with financial and non-financial goals and shareowner interests.

We use independent compensation surveys to benchmark the competitiveness of our compensation practices to peers, primarily major Canadian oil and gas companies and, where relevant, marketing companies. The peer group includes energy companies with whom we compete for talent. Nexen's programs provide responsiveness to changes in the market. We also aim for simplicity in our compensation programs to support communication and employee understanding of the value of the various components. Programs provided for the executives are generally consistent with those provided to all employees in the same location. Where certain programs, such as perquisites, are only provided to executives or senior management, it is reflective of competitive practice and particular business needs and objectives.

In determining base salary, annual cash and long term incentives for executive officers, the Compensation Committee considers individual's performance and recommendations from the CEO and CFO for their respective direct reports, in the context of market data provided by management. The Committee recommends all payments and grants for executive officers to the board or independent directors for approval.

Executive Compensation Objectives

Our compensation programs include three components: base salary, annual cash incentive and long-term incentive. We assess total compensation and consider the competitiveness of each component, both individually and in the aggregate. The overall goal is to provide total compensation for experienced, top-performing employees between the 50th and 75th percentile as compared to peer companies. Nexen's position is compared against the peer group annually.

Key Elements of Compensation

Component	Type of Compensation	Element	Form	Performance Period
Fixed	Annual	Base Salary	Cash	1 Year
Variable	Annual	Annual Cash Incentive	Cash	1 Year
Variable	Long-Term	Long-Term Incentive	TOPs and STARs	Greater than 1 Year

Pay Mix

Nexen's compensation programs are designed to meet both performance and competitiveness objectives, rather than a fixed pay-mix target. As a result, actual pay levels will vary from year to year. In general, the target mix between the compensation elements is designed to provide the majority of compensation to the executive officers in the form of at-risk pay to ensure alignment with shareowners. The annual cash incentive program is designed to reward delivery of results against pre-defined measures within a short time frame. Long-term incentives reward the sustained performance of Nexen as seen in share price appreciation. The actual mix between the compensation elements varies, depending on the ability of the executive to influence short-term and long-term business results, the level and location of the executive, and competitive local market practices. The level of compensation is determined considering the competitive position of each element of compensation on its own, as well as the aggregate of all elements, relative to competitive market data.

Target Weightings for Compensation Elements

		At-Risk Compensation [1]	
Position	Base Salary	Annual Cash Incentive	Long-Term Incentive
CEO	20%	15%	65%
CFO	25%	20%	55%
Senior VPs	30%	20%	50%

Note:
1 *Reported as a percentage of total compensation, excluding benefits, pension and prerequisites.*

Base Salaries

Nexen maintains a framework of job levels based on internal comparability and external market data to determine base salaries. Base salaries are determined within that framework, considering the individual's current and sustained performance, skills and potential. Base salaries are reviewed annually against competitive data from our peer group.

Annual Cash Incentives

Annual incentives provide cash compensation that is at risk and dependent upon the achievement of specific business and operating objectives within a one-year period. Individual awards are intended to reflect a combination of overall Nexen and individual performance, along with market competitiveness. Annual incentive awards are typically within a range of 0% to 200% of targeted amounts.

2006 Annual Incentive Targets [1]

Position	Minimum	Target [2]	Maximum [3]
CEO	0%	75%	150%
CFO	0%	60%	120%
Senior VPs	0%	60%	120%

Notes:
1 *Reported as a percentage of base salary.*
2 *Approved by the board effective January 1, 2006.*
3 *Target at 200%.*

The board, at the recommendation of the Compensation Committee, determines the total cash available for annual cash incentives after reviewing Nexen's annual financial and non-financial incentive measures. The measures in the following balanced scorecard are commonly used metrics in our industry, and are assessed by the Committee in the context of our overall performance and performance relative to peers. The Committee may increase or decrease the total cash available for these awards based on their assessment.

2006 Annual Incentive Measures (Balanced Scorecard)

Financial Performance Measures (50%)

Measure	Actual Results	Results versus Target
Cash flow (25%)	Cash flow was $2,669 million	Exceeded Target
Net income (25%)	Net Income was $601 million	Below Target

Key Qualitative and Quantitative Performance Measures (50%)

Measure	Results versus Target
Overall Business Measures	
Annual stock performance Annual relative stock performance Employee recordable injury index rate Gross corporation G&A Net G&A	The board, at the recommendation of the Compensation Committee, determined that: three of the measures exceeded target, including our annual stock performance with a return of 16% versus a target of 12%; and two were below target.
Growth and Investment Measures	
Realized oil equivalent price Exploration and development project portfolio: Risked Reserve replacement costs: Proved FD&A costs: Proved Recycle ratio Reserve life index	The board, at the recommendation of the Compensation Committee, determined that: three of the measures exceeded target, including reserve life index of 13.2 years versus a target of 12.3 years; and three were below target.
Operational Measures	
Production volumes Operating costs per unit Net oil and gas G&A Net oil and gas G&A per unit Product netback Major environmental incidents	The board, at the recommendation of the Compensation Committee, determined that: two of the measures exceeded target, including operating costs of $8.77 per boe versus a target of $8.86 per boe; one measure, major environmental incidents of zero, met target; and three were below target, including production volumes of 212 thousand boe per day versus a target of 234 thousand boe per day.

The total cash available for annual incentives is distributed to employees, including executives, on the basis of individual performance. Eligibility for awards is defined by individual target award levels that increase in relation to job responsibilities so that the ratio of at-risk versus fixed compensation is greater for higher levels of employees. The program is reviewed annually to ensure we continue to attract, motivate, reward and retain the high-performing and high-potential employees needed to achieve our business objectives, while demonstrating long-term fiscal responsibility to shareowners. Consistent with industry practice, we have a profit sharing arrangement as the annual incentive program for our marketing group. None of the named executive officers participate in the profit sharing arrangement. The Compensation Committee recommends the program for all employees, including executives, to the board for approval.

If, as a result of misconduct, the incentive measures above were restated in a way that decreased the awards, the CEO and CFO would reimburse Nexen proportionately as required by law.

Share Ownership Guidelines

All officers, except Assistant Secretaries, are required to demonstrate their commitment to Nexen through share ownership under the following board-approved guidelines. The period to accumulate shares is five years from date of appointment, and share ownership includes the net value of exercisable options or TOPs, flow-through shares, shares purchased and held within the Nexen employee savings plan and any other personal holdings. All executives hold the required number of shares directly or through the net value of their exercisable options or TOPs. See page 159 for the current share ownership equity at risk as a multiple of salary of each named executive officer. The guidelines are reviewed from time to time.

Position	Required Share Ownership
CEO	Three times annual salary
CFO	Two times annual salary
Other Executive Officers	One times annual salary

Long Term Incentives

The board believes employees should have a stake in Nexen's future and their interests should be aligned with those of shareowners. Those officers and employees whose actions can most directly impact business results, participate in Nexen's long-term incentive program (the TOPs and STARs plans). These plans are Nexen's only equity-based compensation for executives. In addition, we encourage employee purchases of Nexen shares in their savings plan by matching contributions up to specified limits.

Both the TOPs and STARs plans are intended to provide employees with long-term incentive for continued high performance, commitment to Nexen and, more importantly, alignment with the interests of our shareowners. As Nexen's share price rises, grants increase in value. As equity-based plans, the value realized by employees is directly related to changes in Nexen's share price and shareowner interests. If Nexen's share price falls below the exercise price of a grant, the grant will cease to have value until the share price rises above that level.

Effective July 1, 2004, the shareowners approved modifying Nexen's stock option plan to a TOPs plan, which allows employees to exchange their TOPs for a cash payment, equal to the difference between the pre-defined exercise price and the closing market price on that day instead of exercising them for shares. No shares are issued when employees exchange their TOPs for a cash payment, which prevents further shareowner dilution over time, and provides a Canadian income tax deduction to Nexen. The TOPs plan provides employees with the option to buy Nexen shares at a set exercise price at some future date, subject to vesting and expiry terms. These shares may be held or sold at any time. TOPs do not provide employees with the right to vote the shares that are subject to the plan. The TOPs plan is Nexen's only equity-based compensation arrangement for the purposes of disclosure requirements.

Under the TOPs plan, the board, on the recommendation of the Compensation Committee, may grant TOPs to Nexen officers and employees. Options granted before February 2001 have a term of ten years; 20% of the grant vested after six months and then 20% vested each year for four years on the anniversary of the grant. In February 2001, the board approved an amendment providing that each option granted has a term of five years and vests one-third each year over three years.

Generally, if a change of control event occurs (as defined in the TOPs plan), all issued but unvested options will vest.

The STARs plan, introduced in 2001, provides a cash payment to participants equal to the appreciation in Nexen's share price between the date the STARs are granted and the date they are exercised. For employees below mid-level department managers, STARs are typically granted instead of TOPs. The STARs grants have a five-year term and vest one-third in each of the first three years on the anniversary date of the grant.

The long-term incentive program is reviewed annually for competitiveness with our peer group. Market information on options and other forms of long-term incentives, along with the dilutive impact of the program on shareowners, are considered to determine the number of TOPs and STARs granted. Market information is also used to determine the form of long-term incentives and the extent to which employees at different levels participate in the program. Management and the Compensation Committee

have considered alternative long-term incentive programs used by our peers, including full-value plans such as DSUs, restricted share units and performance-based stock options. At this time, the current long-term incentive program has been determined to best meet Nexen's objectives, considering competitive position, retention value, tax effectiveness for our employees and Nexen, shareowner interests, and dilution levels.

Grant Date and Exercise Price

Grants are provided under the TOPs and STARs plans to employees, including executives, during the annual grant process and at the time of hiring key positions. Since 1998, the annual grants have occurred at the December board meeting. Nexen does not springload grants - that is, grants are not intentionally timed to occur immediately prior to the release of material information. Grants for new hires may be approved by the CEO and typically occur shortly after the hire date. Under the plans, the exercise price is the closing market price of Nexen's common shares on the relevant stock exchange (TSX for Canadian-based employees or NYSE for US-based employees) on the day before the grant is approved. Accordingly, back-dating is not allowed. The exercise price of existing TOPs or STARs may not be reduced except for automatic adjustments under the plans, (i.e., share splits) or in accordance with TSX rules.

Grants in the Last Three Years

The focus in 2006 was on providing awards to employees in recognition of high performance, future potential within Nexen and retention risk.

Year	Granted to Executive Officers	Granted to Employees	Percentage of Employees Receiving Grants	Total Number Granted
TOPs				
2006	740,000	1,660,500	7%	2,400,500
2005	592,000	2,799,500	20%	3,391,500
2004[1]	1,022,000	3,202,400	11%	4,224,400
STARs				
2006	–	2,254,300	51%	2,254,300
2005	–	1,443,050	39%	1,443,050
2004[1]	–	2,608,900	34%	2,608,900

Note:
1 Numbers of TOPs and STARs granted have been adjusted to account for Nexen's two-for-one share split in May 2005.

Benefit and Pension Plans

Nexen provides a variety of benefit and pension plans to support the health and well-being of its employees, and to encourage retirement savings. The plans are reviewed from time to time to ensure they remain competitive and continue to meet our objectives. Market survey data is reviewed to ensure the plans provide benefits between the 50th and 75th percentile of plans within our peer group of companies. Executives participate in the same plans provided to all other employees at the same location.

Disclosure in this document is specific to the Canadian and US plans in which the named executive officers participate. Nexen provides a variety of other benefit and pension plans outside of Canada and the US that reflect local market practices.

Health and Welfare Benefits

Nexen employees are provided benefit plans designed to protect their health and that of their dependents, and to cover them in the event of disability or death. Under the North American flexible benefits plan, employees choose the level of coverage that best fits their needs. Those who select enhanced coverage levels are required to contribute to the cost of that coverage.

Employee Savings Plan

Nexen employees have the opportunity to save for short- or long-term needs in the employee savings plan. Through payroll deductions, all eligible Canadian employees may contribute any percentage of their base salary to purchase Nexen common shares, mutual fund units or a combination of both. Nexen matches employee contributions up to 6% of base salary. The extent of matching is based on the investment option chosen and the employee's length of participation in the plan. All Nexen contributions are invested in our common shares purchased on the open market and vest immediately. Canadian employee and employer contributions may be allocated to registered or non-registered accounts. Employees may vote the Nexen common shares they hold in their employee savings plan.

The employee savings plan in the US is intended to qualify under Section 401(a) and 501(a) of the Internal Revenue Code. Nexen matches employee contributions up to 6% of eligible compensation. Nexen's matching contribution is provided in cash, which vests immediately.

Defined Benefit Pension Plan (Canada)

Under this registered plan, participants contribute 3% of their regular gross earnings, up to a plan maximum. On retirement, participants are entitled to receive a benefit equal to 1.8% (1.7% for years prior to 2005) of their average earnings for the 36 highest-paid consecutive months during the ten years before retirement, multiplied by the number of years of credited service. The plan is integrated with the Canada Pension Plan (CPP) to provide a maximum offset of one-half of the prevailing CPP benefit.

Pension benefits earned prior to January 1, 1993, may be indexed at the discretion of management's pension committee, considering increases in the consumer price index. Pension benefits earned after December 31, 1992, are indexed annually at an amount between 0% and 5% and equal to the greater of:

- 75% of the increase in the Canadian consumer price index, less 1%; and
- 25% of the increase in the Canadian consumer price index.

Effective January 1, 2005, the plan was amended to permit participants to periodically switch between the defined benefit pension plan and defined contribution pension plan at different stages in their career. In addition, the defined benefit plan's accrual formula increased from 1.7% to 1.8% for participation after January 1, 2005 as stated above. Plan participants have an opportunity to further increase their defined benefit accrual formula on a go-forward basis, from 1.8% to 2%. Employees who choose this option must contribute an additional 2% of pensionable earnings up to an allowable maximum under the Canadian Income Tax Act. The maximum employee contribution allowed under Nexen's plan in 2006 was $10,200.

Executive Benefit Plan (Canada)

The executive benefit plan provides supplemental retirement benefits for Canadian participants who have earned a retirement benefit in excess of the statutory limits. This supplemental benefit provides employees with the opportunity to accrue a pension that is aligned with their final earnings level and also ensures competitiveness within our market. Benefits that accrue under this plan are similar to the underlying registered pension plan formula for the defined benefit pension plan, which provides for benefits of 1.7% for credited service prior to 2005 and 1.8% or 2% for credited service after that. For executive officers, annual cash incentive payments during the last three years of participation in this plan are included for benefit accrual purposes. For annual cash incentives, the pension benefit is accrued on the lesser of target bonus or actual bonus paid, averaged over the final three years of participation. In 2006, all Canadian executive officers participated in the defined benefit pension plan.

The pension expense for this plan is determined and recognized annually. Benefits payable for the year are paid from the cash flows generated by Nexen's general operating revenues and reduce the related pension liability. As liabilities under this plan are not funded outside of Nexen, a level of protection is provided to participants through a letter of credit. The letter of credit basically makes participants secured creditors up to the aggregate value of the letter of credit. This is separate from the protection of benefits in the registered defined benefit pension plan, which is funded by a pension trust. The cost of servicing the letter of credit for the executive benefit plan for all executive officers and employee participants in 2006 was $465,178.

At December 31, 2006, as indicated in the notes to our Consolidated Financial Statements, Nexen's supplemental pension plan's accumulated benefit obligation (the projected benefit obligation, excluding future salary increases) for the executive benefit plan was $35 million and the projected benefit obligation was $53 million. The projected benefit obligation is an estimate based on contractual entitlements that may change over time. The method used to determine this estimate will not be identical to the method used by other issuers and, as a result, the figures may not be directly comparable across companies. The key assumptions used for the projected benefit obligation were: a discount rate of 5% per year; long-term compensation rate increases of 4% per year; and, an expected average remaining service life of ten years.

Effective January 1, 2005, the executive benefit plan was amended to provide a supplemental pension allocation for defined contribution pension plan participants who are affected by annual statutory contribution limits. In 2006, the supplemental allocation for eligible participants was $29,979 and the supplemental allocation for eligible participants is estimated to be $35,000 in 2007.

Defined Contribution Pension Plan (US)

Under this qualified retirement plan, Nexen provides participants with a contribution of 6% of eligible compensation up to the social security wage base and 11.5% of eligible compensation that exceeds the social security taxable wage base. For 2006, the maximum amount of contributions permitted by legislation to the qualified defined contribution plans was US$20,119 per participant. Employees are not permitted to contribute to the plan. Investment decisions are made by the employee from a variety of mutual funds. The contributions vest after two years of service. This plan is intended to be an Employee Retirement Income Security Act (ERISA) 404(c) plan. In 2006, there was one named executive officer participating in this US plan.

Non-Qualified Restoration Plan (US)

This plan is an unfunded and non-qualified deferred compensation arrangement that provides deferred compensation benefits to a select group of management or senior employees. The returns in this plan reflect the returns on the investments selected by the employee in the defined contribution pension plan (US). The plan is established and maintained by Nexen for the purpose of providing retirement benefits in excess of applicable legislative limits and is intended to comply fully with Section 409A of the Internal Revenue Code.

Loans to Officers

As set out in the corporate governance policy, Nexen does not make loans to its officers. There are no loans outstanding from Nexen to any of its officers.

EXECUTIVE OFFICERS

The board determines the term of office for each executive officer. Below are Nexen's officers, including prior offices and non-executive positions for officers who have held their current executive positions with Nexen for less than five years. Start dates are indicated for officer positions with Nexen.

Officer (Age)	**Current and Past Position(s) with Nexen**	**Effective Date of Current Position**	**Executive Officer Since**
Charles W. Fischer (56)	President and CEO and a director	June 1, 2001	1994
Marvin F. Romanow (51)	Executive VP and CFO	June 1, 2001	1997
Laurence Murphy (55)	Senior VP, International Oil and Gas	January 1, 1999	1998
John B. McWilliams, Q.C. (59)	Senior VP, General Counsel and Secretary	May 11, 1993	1987
Douglas B. Otten (64)	Senior VP, US Oil and Gas	May 12, 1998	1990
Roger D. Thomas (54)	Senior VP, Canadian Oil and Gas	February 19, 1999	1998
Nancy F. Foster (47)	Senior VP, Human Resources and Corporate Services Formerly: VP, Human Resources and Corporate Services	February 15, 2007	2000
Gary H. Nieuwenburg (48)	VP, Synthetic Crude Formerly: VP, Corporate Planning and Business Development since February 16, 2001	July 11, 2002	2001
Kevin J. Reinhart (48)	VP, Corporate Planning and Business Development Formerly: Treasurer since October 20, 1998	July 11, 2002	1994
Una M. Power [1] (42)	Treasurer Formerly: Controller and Director, Corporate Insurance since May 2, 2002; Controller and Director, Risk Management since December 1, 1998	July 11, 2002	1998
Michael J. Harris (43)	Controller Formerly: Manager, Corporate Finance—Treasury since December 1, 2000	December 10, 2002	2002

Note:

1 *Ms. Power concurrently maintained her position as Controller until December 10, 2002.*

SUMMARY COMPENSATION TABLE

The compensation for the CEO, CFO and the next three highest paid officers is provided. The determination of the next three highest paid officers is based on the sum of salary, special bonus and non-equity cash incentive compensation.

		Annual			Long-Term		Other		
Name and Principal Position	Year	Salary	Special Bonus [1]	Non-Equity Cash Incentive Compensation [2]	TOPs Awards [3]	TOPs Awards [3]	Changes in Pension Obligations [4]	All Other Compensation [5]	Total Compensation
		($)	($)	($)	(#)	($)	($)	($)	($)
Fischer, President and CEO	2006	1,150,000	500,000	1,300,000	275,000	5,010,654	1,673,800	101,721	9,736,175
	2005	975,000	300,000	1,500,000	200,000	3,110,490	879,300	91,464	6,856,254
	2004	847,917	450,000	900,000	300,000	1,983,930	1,430,000	84,109	5,695,956
Romanow [6], Executive VP and CFO	2006	528,000	–	402,000	80,000	1,457,645	534,800	111,973	3,034,418
	2005	486,000	175,000	590,000	62,000	964,252	176,300	83,457	2,475,009
	2004	462,500	200,000	350,000	114,000	753,893	346,000	47,569	2,159,962
Otten [7], Senior VP, US Oil and Gas	2006	439,716	–	326,938	55,000	990,017	–	100,303	1,856,974
	2005	423,489	–	430,154	50,000	815,163	–	95,461	1,764,267
	2004	438,005	–	227,763	80,000	572,827	–	111,291	1,349,886
Murphy, Senior VP, International Oil and Gas	2006	455,000	300,000	342,000	65,000	1,184,336	580,800	47,611	2,909,747
	2005	405,000	–	410,000	50,000	777,623	141,300	38,339	1,772,262
	2004	385,500	300,000	205,000	80,000	529,048	104,000	43,620	1,567,168
Thomas, Senior VP, Canadian Oil and Gas	2006	445,000	–	336,000	65,000	1,184,336	735,800	46,986	2,748,122
	2005	394,250	200,000	400,000	50,000	777,623	167,300	44,673	1,983,846
	2004	373,250	–	200,000	80,000	529,048	87,000	37,191	1,226,489

Notes:

1 *Special discretionary award(s) earned in the year shown. For 2006, the board approved a special bonus for Mr. Fischer and Mr. Murphy for the success of Buzzard.*

2 *Reflects the value of awards earned in each year under Nexen's annual cash incentive program. The awards are paid to the executives in the following calendar year.*

3 *Reflects the fair market value under the Black-Scholes pricing model of TOPs granted in the year as described in the TOPs Tables on page 158.*

4 *Represents the employer service cost, plus changes in compensation in excess of actuarial assumptions, less required member contributions to the plan.*

5 *The total value of perquisites provided to each named executive officer is less than both $50,000 or 10% of their total annual salary plus bonus and is not included in this column. Reflects Nexen's contributions to the employee savings plan, defined contribution pension plan (US), car allowance and life insurance premiums paid by Nexen.*

6 *Mr. Romanow is a director of Canexus and was paid fees of $34,000 and received deferred trust units of Canexus valued at $24,000 and distributions on his trust units of $2,571 in 2006. In 2005, he was paid fees of $13,875, received deferred trust units valued at $20,000 and distributions on his trust units of $659. These amounts are included in "All Other Compensation" and more detail is on page 163.*

7 *Nexen contributed to a qualified defined contribution pension plan and a restoration plan with Nexen Petroleum U.S.A. Inc. for Mr. Otten.*

Non-Equity Cash Incentive Compensation and Special Bonus

The summary compensation table above shows the awards for each year, determined under that year's annual cash incentive program. Payment of the awards is made early the following year. Prior to 2006, Nexen reported this award as bonus in the year paid rather than the year earned. Values in the table have been updated to reflect the change in presentation. Special bonuses include discretionary cash awards approved by the board for successful delivery of key business objectives, such as acquisitions and divestitures.

Changes in Pension Obligations

The summary compensation table shows the year-over-year change in pension obligations. The value reflects the employer service cost plus any changes in obligations resulting from compensation increases over actuarial assumptions. Actual compensation changes may vary from the assumed rate of compensation increase and will vary among each executive officer from year to year. These values differ from pension benefit values reported on page 163, which disclose estimated values of annual pension benefits earned to date, as well as at age 60 (the earliest unreduced retirement age). These values also differ from the termination values reported under the change of control agreements on page 164, which disclose the value of additional lump sum pension benefits which will be provided in the event of a change of control.

President and CEO Compensation

Competitive compensation information for our President and CEO is determined based on assessments conducted by an independent compensation consulting firm that compares similar positions in oil and gas companies. Target total direct compensation (base salary plus annual cash and long term incentives) is competitive within the range of our oil and gas peer group. CEO compensation is approved by the independent directors of the board.

President and CEO 2006 Goals

Mr. Fischer's responsibility is to provide direction and leadership in setting and achieving goals, which will create value for Nexen's shareowners in the short- and long-terms. Mr. Fischer's annual cash incentive award for 2006 performance was based on the corporate results described on page 150, which were used to determine the total cash available for the awards. Individual cash incentive awards are determined from the available pool and distributed to individuals based on specific goals established for the year. Based on the board assessment of Mr. Fischer's achievement of objectives in 2006, he was awarded an annual cash incentive of $1,300,000, which was his target bonus times 144%. More specifically, Mr. Fischer's goals in 2006 were to:

- develop and implement corporate strategy, balancing short-term growth while positioning Nexen for sustainable growth;
- achieve capital, operating, and general and administrative cost performance targets set out in the annual operating plan (AOP);
- achieve targets for operating cash flow, earnings, production levels and reserve replacement set out in the AOP;
- maintain financial flexibility and liquidity to support business strategies;
- achieve top-quartile performance in safety, environmental performance and social responsibility;
- provide for corporate management succession and development;
- ensure Nexen adheres to the highest standards of integrity; and
- demonstrate personal commitment to community and industry leadership.

CEO Three-Year Look-Back

The table below outlines the three-year history of compensation paid to Mr. Fischer. The pension service cost from prior years has been updated to reflect the best practice method of reporting the change in pension obligation related to service and earnings increases in that year. The calculation of these numbers in prior years applied a different method that reported the change in pension obligation related to service and earnings increases and non-compensation assumption changes. The values reported previously for 2005 and 2004 were $724,000 and $1,341,000, respectively.

CASH	Total	2006	2005	2004
Base Salary	2,972,917	1,150,000	975,000	847,917
Annual Cash Incentive [1]	4,950,000	1,800,000	1,800,000	1,350,000
EQUITY				
Value of TOPs [2]	10,105,074	5,010,654	3,110,490	1,983,930
Total Direct Compensation	18,027,991	7,960,654	5,885,490	4,181,847
All Other Compensation [3]	277,294	101,721	91,464	84,109
Annual Change in Pension Obligation [4]	3,983,100	1,673,800	879,300	1,430,000
Total	**22,288,385**	**9,736,175**	**6,856,254**	**5,695,956**
Annual Average	7,429,462			
Year-End Market Capitalization (in billions)		17	14	6
Market Capitalization grew by a factor of:	283%			

Notes:

1 *Includes special bonuses of $500,000 in 2006 for the success of Buzzard, $300,000 in 2005 for successful divestitures and $450,000 in 2004 for successful completion of the UK North Sea acquisition.*

2 *Estimated fair value of TOPs using the Black-Scholes pricing model valued on the grant date.*

3 *Reflects Nexen's contributions to the employee savings plan, car allowance and life insurance premiums paid by Nexen.*

4 *Represents the employer service cost, plus changes in compensation in excess of actuarial assumptions, less required member contributions to the plan.*

In addition to the information on the previous page, in 2006 the Compensation Committee reviewed a broader analysis of total CEO pay and shareowner value created from the date Mr. Fischer became CEO. This analysis included a compensation tally sheet outlining a dollar value to each compensation component including: salary, annual cash incentives, awards, benefits, pension (including annual increases to liabilities) and potential payments on change of control. The Committee reviewed total compensation paid to Mr. Fischer since his appointment to the CEO position relative to growth in shareowner value (market capitalization) and that growth relative to our industry peers. All of these factors are considered in determining CEO compensation.

TOPs Tables

Nexen uses the Black-Scholes pricing model, which is a generally accepted method of measurement for this type of long-term incentive, to value TOPs grants. The actual value realized on exercises may be higher or lower than this value depending on the Nexen share price at the time of exercise.

In the following tables, grant prices and numbers granted have been adjusted to account for the May 2005 share split.

TOPs Granted in 2006

Name	Grant Date	TOPs Granted	% of Total TOPs Granted to Employees	Exercise Price[1]	Expiry Date	TOPs Value[2]	Potential Realizable Value at Assumed Annual Rates of Share Price Appreciation for TOPs Term: 5%	10%
		(#)		($)		($)	($)	($)
Fischer	Dec 4, 2006	275,000	5.9	63.20	Dec 3, 2011	5,010,654	4,801,774	10,610,664
Romanow	Dec 4, 2006	80,000	1.7	63.20	Dec 3, 2011	1,457,645	1,396,880	3,086,739
Otten	Dec 4, 2006	55,000	1.2	US$55.00	Dec 3, 2011	990,017	984,746	2,096,479
Murphy	Dec 4, 2006	65,000	1.4	63.20	Dec 3, 2011	1,184,336	1,134,965	2,507,975
Thomas	Dec 4, 2006	65,000	1.4	63.20	Dec 3, 2011	1,184,336	1,134,965	2,507,975

Notes:

1 *The closing market price of Nexen common shares on the TSX or NYSE on December 1, 2006.*

2 *Estimated fair value of the TOPs as at December 4, 2006 using the Black-Scholes pricing model.*

TOPs Exercised or Exchanged and Awards Vested in 2006

	TOPs Awards		Stock Awards [1]	
Name	Exercised or Exchanged	Value Realized [2]	Shares Acquired on Vesting	Value Realized
	(#)	($)	(#)	($)
Fischer	150,000	7,220,550	–	–
Romanow	180,000	7,750,800	–	–
Otten	84,312	3,813,976	–	–
Murphy	49,580	2,415,041	–	–
Thomas	90,000	4,637,950	–	–

Notes:
1 *Nexen does not provide stock awards to its named executive officers.*
2 *Market price at the time of the exercise or exchange, minus the exercise price, as defined in the TOPs plan.*

Equity Ownership and Changes in 2006

Executive officers meet the share ownership guidelines described on page 151. Mr. Fischer is required to hold three times his annual salary, Mr. Romanow is required to hold two times his annual salary and the other executive officers are required to hold one time annual salary.

	Dec 31, 2005		Dec 31, 2006		Net Change		Equity at Risk	
Name	Shares	TOPs [1]	Shares	TOPs [1]	Shares	TOPs [2]	Value ($) [3]	Multiple of Salary [4]
Fischer	74,141	1,146,000	83,258	1,229,000	9,117	83,000	59,947,769	52
Romanow	46,121	492,460	25,937	407,460	(20,184)	(85,000)	18,837,026	36
Otten	55,873	246,636	35,036	230,144	(20,837)	(16,492)	11,678,697	27
Murphy	48,261	99,880	55,828	118,120	7,567	18,240	7,953,430	17
Thomas	1,426	160,080	4,286	134,600	2,860	(25,480)	5,233,475	12

Notes:
1 *Total TOPs granted, vested and unexercised.*
2 *Reflects the number of TOPs that vested, minus the number exercised or exchanged during 2006, as also set out on page 160.*
3 *Equity at risk is the market value of common shares and vested TOPs using the closing price of Nexen shares on the TSX on December 31, 2006 of $64.20.*
4 *Reflects the equity at risk divided by the named executive officer's 2006 salary amount on page 156.*

TOPs Holdings and Value of In-the-Money TOPs

Name	Date Granted	Expiry Date	Grant Price [2]	Granted [2]	Vested and Unvested TOPs at Dec 31, 2006 [1,4] Number	Value [3]	Vested TOPs at Dec 31, 2006 [4] Number	Value [3]
			($)	(#)	(#)	($)	(#)	($)
Fischer	Feb 21, 1997	Feb 20, 2007	11.900	60,000	60,000	3,138,000	60,000	3,138,000
	May 14, 1997	May 13, 2007	14.000	40,000	40,000	2,008,000	40,000	2,008,000
	Feb 27, 1998	Feb 26, 2008	14.150	80,000	80,000	4,004,000	80,000	4,004,000
	Dec 15, 1998	Dec 14, 2008	8.925	100,000	100,000	5,527,500	100,000	5,527,500
	Dec 14, 1999	Dec 13, 2009	13.625	140,000	140,000	7,080,500	140,000	7,080,500
	Dec 12, 2000	Dec 11, 2010	18.050	140,000	140,000	6,461,000	140,000	6,461,000
	Dec 10, 2002	Dec 9, 2007	16.965	200,000	200,000	9,447,000	200,000	9,447,000
	Dec 9, 2003	Dec 8, 2008	21.750	200,000	200,000	8,490,000	200,000	8,490,000
	Dec 7, 2004	Dec 6, 2009	25.435	300,000	300,000	11,629,500	201,000	7,791,765
	Dec 6, 2005	Dec 5, 2010	54.570	200,000	200,000	1,926,000	68,000	654,840
	Dec 4, 2006	Dec 3, 2011	63.200	275,000	275,000	275,000	–	–
Total				**1,735,000**	**1,735,000**	**59,986,500**	**1,229,000**	**54,602,605**
Romanow	Dec 12, 2000	Dec 11, 2010	18.050	100,000	100,000	4,615,000	100,000	4,615,000
	Dec 10, 2002	Dec 9, 2007	16.965	100,000	100,000	4,723,500	100,000	4,723,500
	Dec 9, 2003	Dec 8, 2008	21.750	110,000	110,000	4,669,500	110,000	4,669,500
	Dec 7, 2004	Dec 6, 2009	25.435	114,000	114,000	4,419,210	76,380	2,960,871
	Dec 6, 2005	Dec 5, 2010	54.570	62,000	62,000	597,060	21,080	203,000
	Dec 4, 2006	Dec 3, 2011	63.200	80,000	80,000	80,000	–	–
Total				**566,000**	**566,000**	**19,104,270**	**407,460**	**17,171,871**
Otten	Dec 12, 2000	Dec 11, 2010	18.050	80,000	71,580	3,303,417	71,580	3,303,417
	Dec 10, 2002	Dec 9, 2007	US$10.945	70,000	13,964	698,357	13,964	698,357
	Dec 9, 2003	Dec 8, 2008	US$16.690	74,000	74,000	3,218,224	74,000	3,218,224
	Dec 7, 2004	Dec 6, 2009	US$21.160	80,000	80,000	3,073,213	53,600	2,059,053
	Dec 6, 2005	Dec 5, 2010	US$47.210	50,000	50,000	442,160	17,000	150,335
	Dec 4, 2006	Dec 3, 2011	US$55.000	55,000	55,000	–	–	–
Total				**409,000**	**344,544**	**10,735,371**	**230,144**	**9,429,386**
Murphy	Dec 10, 2002	Dec 9, 2007	16.965	70,000	23,100	1,091,129	23,100	1,091,129
	Dec 9, 2003	Dec 8, 2008	21.750	74,000	24,420	1,036,629	24,420	1,036,629
	Dec 7, 2004	Dec 6, 2009	25.435	80,000	80,000	3,101,200	53,600	2,077,804
	Dec 6, 2005	Dec 5, 2010	54.570	50,000	50,000	481,500	17,000	163,710
	Dec 4, 2006	Dec 3, 2011	63.200	65,000	65,000	65,000	–	–
Total				**339,000**	**242,520**	**5,775,458**	**118,120**	**4,369,272**
Thomas	Dec 9, 2003	Dec 8, 2008	21.750	64,000	64,000	2,716,800	64,000	2,716,800
	Dec 7, 2004	Dec 6, 2009	25.435	80,000	80,000	3,101,200	53,600	2,077,804
	Dec 6, 2005	Dec 5, 2010	54.570	50,000	50,000	481,500	17,000	163,710
	Dec 4, 2006	Dec 3, 2011	63.200	65,000	65,000	65,000	–	–
Total				**259,000**	**259,000**	**6,364,500**	**134,600**	**4,958,314**

Notes:

1 *Excludes grants that have been fully exercised.*

2 *Grant prices and numbers of TOPs granted have been adjusted to account for share splits.*

3 *The difference between the market value of Nexen common shares at year end (TSX—$64.20; NYSE—US $55.00) and the grant price of TOPs, times the number of TOPs.*

4 *The number and value of unvested TOPs can be determined by subtracting the vested TOPs from the vested and unvested TOPs above. The value of unvested TOPs can be confirmed on page 164 in the Change of Control table.*

Pension Plan Tables

All named executive officers, except Mr. Otten, are members of Nexen's registered defined benefit pension plan and executive benefit plan. Mr. Otten is employed in the US and is a member of a qualified defined contribution pension plan and a non-qualified restoration plan, described on page 154.

Estimated Pension Benefit (Canada)

When determining the estimated value of future pension benefits for an executive officer, both tables below need to be referenced. For example, a pension estimate based on 35 years of credited service would require the first table for actual credited service up to and including December 31, 2004, and the second table for credited service on and after January 1, 2005. When estimating future pension benefits, the final average earnings outlined in the "Pension Value Earned in 2006 (Canada)" table on page 162 should be used in both tables. The final average earnings will differ from the three-year average of base salary and cash incentive payments reported in the summary compensation table on page 156 due to the timing of base salary increases and because final average earnings include the lesser of target bonus and actual bonus paid.

This table shows the estimated annual pension a retiring executive officer would receive for credited service to and including December 31, 2004. The annual benefit is based on a pension accrual formula of 1.7% of final average earnings, less a plan CPP offset. It includes benefits from both the defined benefit pension plan and the executive benefit plan and assumes a retirement age of 60, the earliest age at which the individual receives full retirement benefits. The normal benefits paid from these plans are joint life and survivor benefits with a five-year guarantee. The benefit is payable for the participant's lifetime and provides the spouse with a survivor benefit of 66 2/3% of the monthly payment. The five-year guarantee means that if the participant dies before receiving 60 monthly payments, the surviving spouse receives the balance of those 60 monthly payments and then receives the reduced survivor pension of 66 2/3%.

	Years of Credited Service through Dec 31, 2004				
Final Average Earnings ($)	**5**	**10**	**15**	**20**	**25**
400,000	33,276	66,552	99,828	133,104	166,380
600,000	50,276	100,552	150,828	201,104	251,380
800,000	67,276	134,552	201,828	269,104	336,380
1,000,000	84,276	168,552	252,828	337,104	421,380
1,200,000	101,276	202,552	303,828	405,104	506,380
1,400,000	118,276	236,552	354,828	473,104	591,380
1,600,000	135,276	270,552	405,828	541,104	676,380
1,800,000	152,276	304,552	456,828	609,104	761,380
2,000,000	169,276	338,552	507,828	677,104	846,380
2,200,000	186,276	372,552	558,828	745,104	931,380
2,400,000	203,276	406,552	609,828	813,104	1,016,380

This table shows the estimated annual pension benefit a retiring executive officer would receive for credited service earned on and after January 1, 2005, based on a pension benefit accrual formula of 2% of final average earnings, less a plan CPP offset. It includes benefits from both the defined benefit plan and executive benefit plan and assumes a retirement age of 60, the earliest age at which the individual receives full retirement benefits.

	Years of Credited Service from Jan 1, 2005					
Final Average Earnings ($)	2	5	10	15	20	25
400,000	15,710	39,276	78,552	117,828	157,104	196,380
600,000	23,710	59,276	118,552	177,828	237,104	296,380
800,000	31,710	79,276	158,552	237,828	317,104	396,380
1,000,000	39,710	99,276	198,552	297,828	397,104	496,380
1,200,000	47,710	119,276	238,552	357,828	477,104	596,380
1,400,000	55,710	139,276	278,552	417,828	557,104	696,380
1,600,000	63,710	159,276	318,552	477,828	637,104	796,380
1,800,000	71,710	179,276	358,552	537,828	717,104	896,380
2,000,000	79,710	199,276	398,552	597,828	797,104	996,380
2,200,000	87,710	219,276	438,552	657,828	877,104	1,096,380
2,400,000	95,710	239,276	478,552	717,828	957,104	1,196,380

Pension Value Earned in 2006 (Canada)

Additional past service credits or accelerated service credits must be approved by the board. No accelerated service credits were authorized in 2006. Additional past service credits authorized by the board for the named executive officers who participate in the Canadian defined benefit pension plan and the executive benefit plan are noted below. Final average earnings for each named executive officer is his:

- average base salary for the 36 highest paid consecutive months during the ten years before retirement;
- plus annual cash incentive payments at the lesser of target bonus or actual bonus paid, averaged over the final three years of participation.

	Years of Credited Service						
Name	Up to Dec 31, 2004	From Jan 1, 2005	Total	Final Average Earnings [1]	Accrued Annual Pension Benefit [1]	Estimated Annual Pension Benefit at Age 60 [2]	Benefit Payments During the Last Fiscal Year [3]
	(#)	(#)	(#)	($)	($)	($)	($)
Fischer	20.58 [4]	2.00	22.58	1,628,472	631,698	951,321	–
Romanow [5]	17.50 [4]	2.00	19.50	743,267	278,977	476,898	–
Murphy	18.67	2.00	20.67	585,100	206,087	310,285	–
Thomas	24.50 [4]	2.00	26.50	569,367	256,079	392,713	–

Notes:

1 *All information as of December 31, 2006.*

2 *Earliest age at which an individual receives full retirement benefits.*

3 *There were no benefit payments made to the named executive officers in 2006.*

4 *Ten years of additional past service credits were granted to each of Messrs. Fischer, Romanow and Thomas by the board in 2001.*

5 *Mr. Romanow joined the defined benefit pension plan following 7.25 year in the defined contribution pension plan. The pensionable bonus provision recognizes a pension benefit for Mr. Romanow based on his combined 26.75 years of service, while the base salary provision recognizes a pension benefit for his 19.5 years of defined benefit pension plan service only. The value of the pension benefit resulting from the additional 7.25 years is reflected in the pension benefit values above.*

Pension Benefit Obligation Increase in 2006 (Canada)

Reported values use actuarial assumptions and methods consistent with those used in the calculation of pension liabilities and the related annual expense as disclosed in our financial statements. As the assumptions reflect our best estimate of future events, they may not be directly comparable to similar pension liability values disclosed by other companies.

Name	Obligation at Dec 31, 2005	Changes Related to Current Service Cost and Earnings Increases [1]	Changes Related to Financing Costs and Non-Compensation Assumption Changes [2]	Change in Obligation since Dec 31, 2005	Obligation at Dec 31, 2006
Fischer	8,687,000	1,673,800	797,000	2,470,800	11,157,800
Romanow	3,464,000	534,800	298,000	832,800	4,296,800
Murphy	2,502,000	580,800	205,000	785,800	3,287,800
Thomas	3,209,000	735,800	251,000	986,800	4,195,800
Total	**17,862,000**	**3,525,200**	**1,551,000**	**5,076,200**	**22,938,200**

Notes:

1 *Includes the 2006 employer service cost, plus changes in compensation in excess of actuarial assumptions, less required member contributions to the pension plan.*

2 *Reflects the impact of interest on prior year's obligations, changes in discount rates used to measure the obligations, the impact of assumption changes and experience gains and losses other than those related to compensation.*

Pension Value Earned in 2006 (US)

Mr. Otten is the only named executive officer who is a member of this US pension plan. He has not made any withdrawals in 2006.

Name	Contributions under the Defined Contribution Pension Plan	Contributions under the Non-Qualified Restoration Plan	Total Pension Compensation
Otten	22,839	44,888	67,727

All Other Compensation Table

The total value of perquisites provided to any one executive officer was less than both $50,000 or 10% of the named executive officer's total annual salary plus bonus in 2006 and, accordingly, is not disclosed. The car allowance, which provides direct monetary value to the executive, is reported.

Name	Car Allowance	Life Insurance Premiums	Savings Plan Contributions	Amounts Paid by Canexus	US Pension Contributions	Total All Other Compensation
Fischer	31,200	1,521	69,000	–	–	101,721
Romanow	19,200	522	31,680	60,571	–	111,973
Otten	16,347	2,670	13,559	–	67,727	100,303
Murphy	19,200	1,111	27,300	–	–	47,611
Thomas	19,200	1,086	26,700	–	–	46,986

Note:

1 *Includes fees of $34,000, deferred trust units of Canexus valued at $24,000 and distributions on his trust units of $2,571.*

CHANGE OF CONTROL AGREEMENTS

Nexen has entered into change of control agreements with Messrs. Fischer, Romanow, Otten, Murphy, Thomas and other key executives. The agreements were effective October 1999, amended in December 2000 and amended and restated in December 2001. The agreements recognize that these executives are critical to Nexen's ongoing business. They recognize the need to retain the executives, protect them from employment interruption caused by a change in control and treat them in a fair and equitable manner. Consistent with industry standards for executives in similar circumstances, there are no restrictions on future employment or non-compete clauses in the agreements. Each year, the Committee reviews the estimated payments on change of control including the termination value of pension benefits due under the registered pension and executive benefit plans.

Under these agreements, a change of control includes any acquisition of common shares or other securities that carry the right to cast more than 35% of the votes attached to all issued common shares and generally, any event, transaction or arrangement that results in a person or group exercising effective control of Nexen.

If the named executives terminate following a change in control, they are entitled to receive salary, target bonus and benefits for a specified severance period. For Mr. Fischer and Mr. Romanow, the severance period is 36 months if they are terminated. Both of them may also voluntarily terminate their employment within 12 months following a change of control with severance periods of 36 and 30 months, respectively. For Messrs. Otten, Murphy and Thomas, the severance period is 30 months, only if they are terminated following a change of control.

The table below outlines the estimated incremental payments had a change of control occurred on December 31, 2006. The cost of base salary, bonus and benefits represents the value of those compensation elements for the duration of the severance period. Under the terms of the agreement, bonus is paid at target for the severance period. A benefits uplift, equal to 13% of base salary, is provided in lieu of medical, dental and life insurance coverage. In addition, the agreement provides a payment for other employee benefits, which includes such items as car allowance and savings plan contributions during the severance period and an allowance for financial counselling and career transition services.

The pension value reported is the incremental value of pension resulting from the recognition of salary and target bonus over the severance period, as well as a tax gross-up on the resulting lump sum payout. These additional pension benefits do not include the termination benefits payable from the underlying registered pension plan and executive benefit plan that would occur in the event of a termination or retirement not triggered by a change of control. Regular termination values, calculated as at December 31, 2006, are set out in the footnotes to the following table. The table does not include TOPs currently vested and unexercised as described on page 160.

Estimated Incremental Payment on Change of Control [1]

Name	Severance Period	Base Salary	Bonus Target Value	Benefits Uplift	Other Employee Benefits	Additional Lump Sum Value of Pension [2]	Accelerated TOPs Value [3]	Total Incremental Payment
	(# of months)	($)	($)	($)	($)	($)	($)	($)
Fischer [4]	36	3,600,000	2,700,000	468,000	347,500	9,426,000	5,383,895	21,925,395
Romanow	36	1,620,000	972,000	210,600	192,700	3,563,000	1,932,399	8,490,699
Otten [5]	30	1,135,200	567,600	147,576	165,626	181,119	1,305,985	3,503,106
Murphy	30	1,175,000	587,500	152,750	156,400	2,410,000	1,406,186	5,887,836
Thomas	30	1,150,000	575,000	149,500	154,900	3,095,000	1,406,186	6,530,586
Total		**8,680,200**	**5,402,100**	**1,128,426**	**1,017,126**	**18,675,119**	**11,434,651**	**46,337,622**

Notes:

1 *Assumes a triggering event occurred on December 31, 2006.*

2 *Does not include regular termination pension values for Messrs. Fischer ($9,850,000), Romanow ($3,108,000), Murphy ($3,013,000) and Thomas ($3,188,000). The values in this note include the pension benefit payable under the registered pension plan funded from the pension trust and are payable monthly if the named executive officer is 55 or older.*

3 *Value of TOPs that automatically vest on a change of control, based on the number of TOPs with accelerated vesting, times the closing price of Nexen common shares on the TSX on December 31, 2006 of $64.20, less the exercise price.*

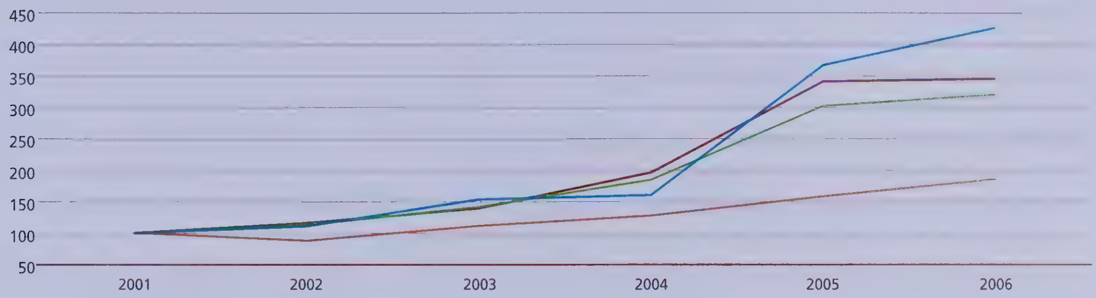
4 *For Mr. Fischer only, the additional lump sum value of pension includes an incremental cost for an early retirement reduction that is waived under the agreement.*

5 *Mr. Otten is a member of the Defined Contribution Pension Plan (US) and the Non-Qualified Restoration Plan.*

SHARE PERFORMANCE GRAPH

The following graph shows five years of change in the value of $100 invested in our common shares, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index as at December 31, 2006. Our common shares are included in each of these indices.

Total Return Index Values [1]



	2001/12	2002/12	2003/12	2004/12	2005/12	2006/12
Nexen Inc.	100.00	111.08	153.52	160.59	367.13	426.65
S&P/TSX Energy Sector Index	100.00	113.74	142.14	185.19	302.67	321.00
S&P/TSX Oil & Gas Exploration & Production Index	100.00	116.17	139.58	196.35	340.96	345.47
S&P/TSX Composite Index	100.00	87.56	110.96	127.03	157.68	184.89

Note:

1 *Assuming an investment of $100 and the reinvestment of dividends.*

CORPORATE GOVERNANCE

Nexen's board takes its duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules of the Toronto Stock Exchange (TSX), NYSE, *National Policy 58-201—Corporate Governance Guidelines* and *Multilateral Instrument 52-110—Audit Committees*. Except as noted below with regard to DSUs, Nexen's corporate governance practices comply with the corporate governance practices followed by domestic companies under NYSE listing standards.

Nexen has a DSU plan for non-executive directors as described on page 146. For this plan, Nexen follows the TSX rules which, unlike the NYSE rules, exempt plans from shareowner approval where the common shares issued under the plan are purchased on the open market rather than issuing new shares.

On February 26, 2007, our CEO certified to the NYSE that he was unaware of any violation by Nexen of the NYSE's corporate governance listing standards. Nexen also provided the required Annual Written Affirmation to the NYSE on February 26, 2007. Nexen also filed an Interim Written Affirmation on April 28, 2006. As well, our CEO and CFO have certified the quality of Nexen's public disclosure to the SEC.

All Committee Mandates, including those for the Audit, Compensation and Governance Committees, and our corporate governance policy and categorical standards are available at www.nexeninc.com, and we intend to provide disclosure in this manner. Shareowners wishing to receive a copy of these documents may contact the Governance Office by telephone at 403.699.4926, by facsimile at 403.699.7062 or by email at governance@nexeninc.com.

GOVERNANCE COMMITTEE REPORT

The Governance Committee assists the board in overseeing implementation of our corporate governance programs, recommending nominees for director appointments and evaluating the board, its committees and all individual directors and chairs, to ensure Nexen is implementing best-in-class corporate governance practices.

Principles and Systems for the Management of Corporate Governance

Nexen's board and management are committed to best practices in corporate governance as evidenced by the Committee's annual activities and its commitment to continuous improvement.

Key Activities in 2006

- Recommended changes to membership on the committees;
- Recommended the appointment of A. Anne McLellan, P.C. to the board;
- Recommended the adoption of a modified majority vote by-law for the election of directors;
- Recommended revisions to the corporate governance policy and external communications policy;
- Recommended revised mandates or position descriptions for the board, individual directors, all board committees, the chairs, CEO, CFO and Secretary; and
- Consulted with Dr. Richard Leblanc, Assistant Professor of Corporate Governance, York University, on the board's performance evaluations.

Identifying Qualified Candidates for Board and Committee Appointments

The Committee reviews the make up of the board and committee appointments of all directors annually and makes recommendations to the board. The Committee considers the independence tests set out in our categorical standards, together with the skills and preferences of the directors, in making its recommendations. The board is comprised of 12 directors, which is large enough to permit a diversity of views and staff the committees, without being so large as to detract from efficiency and effectiveness. A skills matrix that sets out the various areas of expertise determined to be essential to ensure appropriate strategic direction and oversight is completed by all directors annually and reviewed by the Committee. The Committee's review of board experience indicates that the current skills mix is appropriate. The skills matrix is also used to assist with board recruitment. Character and behavioural qualities, including credibility, integrity and communication skills are also taken into account when recruiting new directors.

The Committee maintains an evergreen list of potential board directors comprised of people who the Committee recommends to be asked to join the board when they are available and whose skills would complement the board.

The Committee will consider any nominee for election as a director recommended by a shareowner. See page 168 for communicating with the board.

In 2006, the composition of committees was revised, in part, to allow for committee chair rotation and to address shareowner concerns with former Nexen CEOs on independent committees. In addition to the changes to the Compensation Committee, noted in their report, the following changes were made:

- Mr. Flanagan left as the Reserves Chair;
- Mr. Hentschel left Audit and Compensation, and joined Finance;
- Mr. Jenkins left as Finance Chair and joined Compensation as its Chair;
- Mr. O'Neill moved from SESR to Compensation;
- Mr. Willson left Finance and SESR, and came off as Compensation Chair; he joined Audit and Governance and became Reserves Chair; and
- Mr. Zaleschuk left Compensation and Governance, joined SESR, and became Finance Chair.

Performance Evaluations

The Committee conducts an annual six-part performance evaluation review during the period from October through January designed to enable the board and individual directors to examine their effectiveness and establish goals for continuous improvement. The effectiveness criteria incorporate current best practices and Nexen's current governance documents.

External Recognition and Verification

Nexen was recognized for its governance practices during 2006, including the following:

- Named sixth on the list of the Top 25 Boards in Canada by Canadian Business Magazine;
- Acknowledged by the Canadian Coalition for Good Governance for seven best practices and two innovations in shareowner communication and two best practices in compensation disclosure;
- Had an average 2006 global rating of 9.9 out of 10 and have a current rating of 10 from GovernanceMetrics International for governance practices and disclosure; and
- John McWilliams, Q.C., received the Canadian General Counsel Award for Corporate Governance.

Committee Approval

The Committee has reviewed and discussed the governance disclosure included in this document and has recommended to the board that it be included in the Form 10-K.

Submitted on behalf of the Governance Committee:

Dick Thomson, Chair	Tom O'Neill
Dennis Flanagan	Francis Saville
Kevin Jenkins	John Willson
Anne McLellan	

Ethics Policy

Under our ethics policy, all directors, officers and employees must demonstrate a commitment to ethical business practices and behaviour in all business relationships, both within and outside of Nexen. Employees are not permitted to commit an unethical, dishonest or illegal act or to instruct other employees to do so. Our ethics policy has been adopted as a code of ethics for our principal executive officer, principal financial officer and principal accounting officer or controller.

Any waivers of, or changes to the ethics policy must be board approved and disclosed. There have been no waivers since January 1, 2006, or ever. The ethics policy was amended on February 14, 2007. We made minor revisions to the integrity-related policies section, re-wrote the prevention of improper payments policy description, and added subsections for the gifts and entertainment and information technology acceptable use policies. Our ethics policy provides for an external integrity hotline, since February 1, 2005.

Nexen's ethics policy is available at www.nexeninc.com and we intend to disclose any waivers of or changes to this policy online. Our ethics policy and any future amendments to it are filed on SEDAR at www.sedar.com. To request a copy of the policy, contact the Governance Office by calling 403.699.4926, faxing 403.699.7062 or emailing governance@nexeninc.com.

Reporting Concerns

Please direct any concerns about Nexen's financial statements, accounting practices or internal controls to either: (i) management or the Chair of the Audit Committee as set out in the ethics policy; or, (ii) EthicsPoint, as set out below.

Employees, customers, suppliers, partners, shareowners and other external stakeholders who have a concern, are encouraged to raise it with our Integrity Resource Centre:

By mail:	Nexen Inc. 801 - 7th Avenue SW Calgary, Alberta, Canada T2P 3P7 Attention: Integrity Resource Centre
By email:	integrity@nexeninc.com
By telephone:	403.699.4727

You may also report concerns through our integrity hotline – a secure reporting system, which is owned and managed by EthicsPoint, an independent third-party service provider. To find out more about our integrity hotline and for toll free numbers for other countries, access our web site at www.nexeninc.com and click on the "Integrity Hotline" link at the top of the page or access the hotline directly:

Online:	www.ethicspoint.com
By toll-free telephone:	1.866.384.4277 (North America)

Communicating with the Board

Shareowners may write to the board or any member or members of the board in care of the following address:

By mail:	Nexen Inc. 801 - 7th Avenue SW Calgary, Alberta, Canada T2P 3P7 Attention: John B. McWilliams, Q.C. Senior Vice President, General Counsel and Secretary
By email:	board@nexeninc.com

We receive a number of inquiries on a large range of subjects every day. The board has consulted with management to develop a process to assist in managing inquiries directed to the board or its members.

Letters and emails addressed to the board, any of its members or the independent directors, as a group, are reviewed to determine if a response from the board is appropriate. While the board oversees management, it does not participate in our day-to-day functions and operations and is not normally in the best position to respond to inquiries on those matters. Those inquiries will be directed to the appropriate personnel for response. The board has instructed the Secretary to review all correspondence and, in his discretion, not forward items that are:

- not relevant to Nexen's operations, policies or philosophies;
- commercial in nature; or
- not appropriate for consideration by the board.

All inquiries will receive a response from the board or management. The Secretary maintains a log of all correspondence sent to board members. Directors may review the log at any time and request copies of any correspondence received.

AUDIT COMMITTEE

See page 171 for a full report on the Audit Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities. Based on information known to Nexen, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of Nexen's voting securities at December 31, 2006.

Name and Address of Beneficial Owner	# of Shares Beneficially Owned	% of Shares
Ontario Teachers' Pension Plan Board [1] 5650 Yonge Street Toronto, Ontario, Canada, M2M 4H5	30,088,836	11.5%
Jarislowsky, Fraser Limited [2] Suite 2005, 1010 Sherbrooke Street West Montreal, Quebec, Canada, H3A 2R7	29,363,678	11.19%
Capital Research and Management Company [3] 333 South Hope Street Los Angeles, California, USA, 90071	13,697,880	5.2%

Notes:

1 *The beneficial owner has sole voting and power to dispose of all shares.*

2 *The beneficial owner has sole voting power over 24,054,458 shares, shared voting power over 5,309,220 shares and sole power to dispose of all shares.*

3 *The beneficial owner has sole voting power over 5,187,360 shares, sole power to dispose of all shares and disclaims beneficial ownership pursuant to Rule 13d-4.*

SECURITY OWNERSHIP OF MANAGEMENT

At February 15, 2007, the following directors, certain executive officers, and all directors and executive officers as a group beneficially owned the following Nexen common shares:

Name of Beneficial Owner	Number of Shares [1]	Exercisable TOPs [2]
Charles W. Fischer	83,581	1,169,000
Dennis G. Flanagan	12,002	13,630
David A. Hentschel	11,380	61,000
S. Barry Jackson	25,000	11,000
Kevin J. Jenkins	6,166	41,000
A. Anne McLellan, P.C.	–	–
Eric P. Newell, O.C.	6,000	–
Thomas C. O'Neill	8,000	11,000
Francis M. Saville, Q.C.	20,800	39,132
Richard M. Thomson, O.C.	46,002	91,600
John M. Willson	14,002	3,666
Victor J. Zaleschuk	31,451	120,000
Laurence Murphy	55,946	118,120
Douglas B. Otten	35,036	230,144
Marvin F. Romanow	26,068	407,460
Roger D. Thomas	4,395	134,600
All directors and executive officers as a group (22 persons)	487,944	2,940,372

Notes:

1 *The number of shares held and TOPs exercisable by each beneficial owner represents less than 1% of the shares outstanding.*

2 *Includes all TOPs exercisable within 60 days of February 15, 2007. All TOPs held by non-executive directors are vested.*

Under the terms of our TOPs Plan, the board may grant options to officers and employees and, when previously allowed for, to directors. Nexen does not receive any consideration when options are granted.

Plan Category	Number of Securities to be Issued on Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by shareowners	15,242,292	$35/option	16,235,167
Equity compensation plans not approved by shareowners	–	–	–
Total	**15,242,292**	**$35/option**	**16,235,167**

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

As a Canadian foreign private issuer, Nexen provides the disclosure required under Item 7.B. of Form 20-F dealing with "related party transactions." Nexen did not have any related party transactions in 2006 as defined under that standard. Certain other transactions described below, involving Nexen and certain of our directors were entered into in 2006. These transactions are not, related party transactions.

Mr. Saville, a director, was a senior partner of Fraser Milner Casgrain (FMC), Barristers and Solicitors, Calgary, Alberta, until the end of January 2004. Since then, he has been counsel with FMC. FMC provided legal services to Nexen during each of the last five years. Mr. Saville neither solicits nor participates in the services rendered to Nexen and does not receive any portion or percentage of the fees paid by Nexen to FMC. In addition, Mr. Saville is considered to be an independent director pursuant to our Categorical Standards.

Ms. McLellan, a director, is counsel of Bennett Jones (BJ), Barristers and Solicitors, Edmonton, Alberta. BJ provided legal services to Nexen during each of the last five years. Ms. McLellan neither solicits nor participates in the services rendered to Nexen and does not receive any portion or percentage of the fees paid by Nexen to BJ. In addition, Ms. McLellan is considered to be an independent director pursuant to our Categorical Standards.

Mr. Flanagan's son is Senior Vice President, Engineering of TriAxion Resources Ltd. (TriAxion). In 2006, TriAxion acquired a company that was party to a commodity contract and a hedge contract with a wholly-owned subsidiary of Nexen. The commodity contract was later replaced with two new contracts dated effective June 1, 2006. No payments were made in 2006 under one of those contracts. For the other, however, Nexen paid approximately $4.5 million to TriAxion between July and December 2006 for products purchased at market price. Accordingly, Mr. Flanagan will not technically be independent as of July 1, 2007. Mr. Flanagan was not aware that the company acquired by TriAxion held contracts with Nexen. The board has determined that Mr. Flanagan's intellectual independence was in no way impaired by this transaction.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AUDIT COMMITTEE REPORT

The Audit Committee is directly responsible for appointing (subject to shareowner approval), compensating and overseeing the independent registered Chartered Accountants (independent auditors). The independent auditors are accountable to and report directly to the Committee, and understand that they must maintain an open and transparent relationship with the Committee, as representatives of the shareowners.

The Committee assists the board in overseeing internal accounting and financial reporting controls, internal and external audit processes, and implementation of the ethics policy.

Management is responsible for our internal controls and financial reporting process. The independent auditors are responsible for performing and reporting on an independent audit of our consolidated financial statements according to generally accepted auditing standards. The independent auditors also perform and report on an independent audit of our internal control over financial reporting according to the standards of the US Public Company Accounting Oversight Board. The Committee's responsibility is to monitor and oversee these processes.

Key Activities for 2006

- Met separately with management and the independent auditors to review the December 31, 2006 consolidated financial statements;
- Discussed with the independent auditors matters required by Canadian regulators under Section 5751 of the General Assurance and Auditing Standards of the Canadian Institute of Chartered Accountants "Communications with Those having Oversight Responsibility for the Financial Reporting Process" and by US regulators under the Statement on Auditing Standards No. 61 "Communication with Audit Committees" issued by the American Institute of Certified Public Accountants;
- Received written disclosures from the independent auditors required by the SEC according to the Independence Standards Board Standard No. 1 "Independence Discussions with Audit Committees";
- Based on the reviews and discussions referred to above, recommended to the board that the audited financial statements be included in Nexen's annual report on Form 10-K;
- Discussed with the independent auditors that firm's independence;
- Oversaw the progress of Section 404 Sarbanes-Oxley compliance activities undertaken by management and the independent auditors to report on the effectiveness of internal control over financial reporting as at December 31, 2006; and
- Recommended changes to the ethics policy.

Audit Partner Rotation

In compliance with applicable law, the lead audit partner of our independent auditors is replaced every five years.

Section 404 of Sarbanes-Oxley

Nexen is a voluntary filer of Form 10-K in the US and, due to this, has been required to comply with the requirements of Section 404 of Sarbanes-Oxley since December 31, 2004. During 2006, management evaluated the effectiveness of our internal control over financial reporting and concluded that it was effective as of December 31, 2006. This assessment was documented and audited by the independent auditors as part of the integrated audit of the consolidated financial statements. Their report is included in our Form 10-K.

Auditor Engagement

Before Deloitte & Touche LLP is engaged by Nexen or its subsidiaries to render audit or non-audit services, the engagement is approved by the Committee. All audit-related, tax and other services provided by Deloitte & Touche LLP since May 6, 2003, have been approved by the Committee.

Fees Billed by Independent Auditors

Type of Fee	Billed in 2005	Billed in 2006	Percentage of Total Fees Billed in 2006
Audit Fees			
For the integrated audit of Nexen's consolidated financial statements included in our annual report on Form 10-K	2,075,500 [1]	2,332,500 [2]	
For the integrated audit of the consolidated financial statements of Canexus [3]	–	302,900 [4]	
For the first, second and third quarter reviews of Nexen's consolidated financial statements included in Form 10-Qs	69,000	72,000	
For the first, second and third quarter reviews of the consolidated financial statements of Canexus [3]	–	45,000	
For comfort letters and submissions to commissions	149,000	2,500	
Total Audit Fees	**2,293,500**	**2,754,900**	**76%**
Audit-Related Fees — Nexen and Canexus [3]			
For the annual audits and quarterly reviews of subsidiary financial statements and employee benefit plans	466,500	719,500	
For audit-related work in connection with acquisitions and divestitures	391,000	–	
Total Audit-Related Fees	**857,500**	**719,500**	**20%**
Tax Fees — Nexen and Canexus [3]			
For tax return preparation assistance and tax-related consultation	234,000	84,300	
Total Tax Fees	**234,000**	**84,300**	**2%**
All Other Fees	**66,000** [5]	**86,000** [5]	**2%**
Total Annual Fees	**$3,451,000**	**$3,644,700**	**100%**

Notes:

1 *Consisting of $885,500 to complete the 2004 audit and $1,190,000 to commence the 2005 audit.*
2 *Consisting of $1,032,500 to complete the 2005 audit and $1,300,000 to commence the 2006 audit.*
3 *Includes fees for Canexus Income Fund, Canexus Limited Partnership and its subsidiaries.*
4 *Consisting of $105,000 for the 2005 audit and $197,900 to commence the 2006 audit.*
5 *Annual renewal fees for an upstream information database used in our UK office.*

Committee Approval

The Committee is of the view that the provision of services by Deloitte & Touche LLP described in "All Other Fees" above is compatible with maintaining that firm's independence.

Based on the Committee's discussions with management and the independent auditors, and its review of the representations of management and the independent auditors, the Committee recommended that the board include the audited consolidated financial statements in Nexen's annual report on Form 10-K for the year ended December 31, 2006.

Submitted on behalf of the Audit Committee:

Tom O'Neill, Chair
Dennis Flanagan
Barry Jackson
Kevin Jenkins
Dick Thomson
John Willson

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS AND SCHEDULES

We refer you to the index to Financial Statements and Supplementary Data in Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted because they are not required or applicable, or the required information is shown in the Consolidated Financial Statements or notes.

EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

2.2 Agreement for the Sale and Purchase of EnCana (U.K.) Limited, between EnCana (U.K.) Holdings Limited and Nexen Energy Holdings International Limited dated October 28, 2004 (filed as Exhibit 2.1 to Form 8-K dated October 29, 2004).

3.9 By-Law No. 2 of the Registrant enacted December 9, 2003, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 3.9 to Form 10-K for the year ended December 31, 2003).

3.14 Restated Certificate and Articles of Incorporation of the Registrant dated May 20, 2005 (filed as Exhibit 3.12 to Form 10-Q for the quarterly period ended June 30, 2005).

3.15 By-Law No. 3 of the Registrant enacted December 4, 2006, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 3.15 to Form 8-K dated December 5, 2006).

4.29 Acquisition Agreement between the Registrant, Occidental Petroleum Corporation and Ontario Teachers' Pension Plan Board, dated March 1, 2000 (filed as Exhibit 4.29 to Form 10-K for the year ended December 31, 1999).

4.42 Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company providing for the issue of debt securities from time to time (filed as Exhibit 4.42 to Form 10-K for the year ended December 31, 2003).

4.43 First Supplemental Indenture dated April 28, 1998 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$200 million, 7.40% notes due 2028 (filed as Exhibit 4.43 to Form 10-K for the year ended December 31, 2003).

4.46 Third Supplemental Indenture dated March 11, 2002 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of $500 million, 7.85% notes due 2032 (filed as Exhibit 4.46 to Form 10-K for the year ended December 31, 2003).

4.47 Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of subordinated notes from time to time (filed as Exhibit 4.47 to Form 10-K for the year ended December 31, 2003).

4.48 Officer's Certificate dated November 4, 2003 pursuant to the Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issuance of US$460 million, 7.35% subordinated notes due 2043 (filed as Exhibit 4.48 to Form 10-K for the year ended December 31, 2003).

4.51 Fourth Supplemental Indenture dated November 20, 2003 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$500 million, 5.05% notes due 2013 (filed as Exhibit 4.51 to Form 10-K for the year ended December 31, 2003).

4.53	Fifth Supplemental Indenture dated March 10, 2005 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$250 million, 5.20% notes due 2015 and the issuance of US$790 million, 5.875% notes due 2035 (filed as Exhibit 10.1 to Form 8-K dated March 11, 2005).
4.54	Amended and Restated Shareholder Rights Plan Agreement dated April 27, 2005 between the Registrant and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A (filed as Exhibit 4.54 to Form 10-K for the year ended December 31, 2005).
10.40	Amended and Restated Change of Control Agreements with Executive Officers dated during December, 2001 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2001).
10.41	Indemnification Agreements made between the Registrant and its directors and officers during 2002 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002).
10.42	Indemnification Agreement made between the Registrant and one of its directors, Eric P. Newell, as of January 5, 2004 (filed as Exhibit 10.42 to Form 10-K for the year ended December 31, 2003).
10.43	Credit Agreement dated as of July 22, 2005 between the Registrant and the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 28, 2005).
10.44	Guarantee dated as of July 22, 2005 as Schedule K to the Credit Agreement (filed as Exhibit 10.2 to Form 8-K dated July 28, 2005).
10.45	Termination of Employment and Special Separation Agreement between the Registrant and Mr. Sugalski dated January 28, 2005 (filed as Exhibit 10.1 to Form 8-K/A dated August 18, 2005).
10.46	Indemnification Agreement made between the Registrant and one of its directors, A. Anne McLellan P.C., as of July 5, 2006 (filed as Exhibit 10.2 to Form 8-K dated July 20, 2006).
10.47	Second Amending Agreement dated July 14, 2006 to the Credit Agreement, dated as of July 22, 2005, between the Registrant and the Toronto-Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 20, 2006).
11.1*	Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2006.
16.1	Letter re change in certifying accountant (filed as Exhibit 16.1 to Form 8-K filed July 17, 2002).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of Independent Registered Chartered Accountants.
23.2*	Consent of William M. Cobb & Associates, Inc.
23.3*	Consent of Ryder Scott Company, L.P.
23.4*	Consent of McDaniel & Associates Consultants Ltd.
23.5*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Opinion of Internal Qualified Reserves Evaluator on National Instrument 51-101 Form F2 as required by certain Canadian securities regulatory authorities.

* *Filed with this Form 10-K.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 26, 2007.

NEXEN INC.
By: /s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 26, 2007.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ A. Anne McLellan
A. Anne McLellan, Director

/s/ Eric P. Newell
Eric P. Newell, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Michael J. Harris
Michael J. Harris
Controller
(Principal Accounting Officer)

/s/ John B. McWilliams
John B. McWilliams
Senior Vice President, General Counsel
and Secretary

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Vice President, Corporate Planning
and Business Development

EXHIBIT 31.1

Certifications

I, Charles W. Fischer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2007

/s/ Charles W. Fischer
Charles W. Fischer
President and Chief Executive Officer

EXHIBIT 31.2

Certifications

I, Marvin F. Romanow, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2007

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President
and Chief Financial Officer

EXHIBIT 32.1

Certification Of Periodic Report

I, Charles W. Fischer, President and Chief Executive Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2007

/s/ Charles W. Fischer
Charles W. Fischer
President
and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

EXHIBIT 32.2

Certification Of Periodic Report

I, Marvin F. Romanow, Executive Vice President and Chief Financial Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2007

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President
and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

Corporate and Other Information

Building world-class capacity requires a solid track record of performance, reputation and results. Our reserves data, 5-year performance review and awards demonstrate this strong foundation.

CORPORATE AND OTHER INFORMATION

Receiving Recognition

In all areas of our business, our commitment to excellence is noticed and rewarded. We are very proud of the following awards. They reflect our values and pay big dividends in the long run.

Safety and Operating

Producer of the Year
Oilweek Magazine
November 2006

BG Chairman's Contract Partner Performance Award
Safety in a major project category: awarded for our Buzzard project
June 2006

2005 Safety Award for Excellence in the Gulf of Mexico
United States Minerals Management Service: awarded for the second year in a row
April 2006

Leadership and Our People

50 Best Employers in Canada
Hewitt Associates
January 2007

Top 25 Employers in Alberta
Mediacorp Canada Inc.
October 2006

Canadian Engineering Leader Award
Charlie Fischer, President and CEO
Schulich School of Engineering
November 2006

Top General Counsel in Corporate Governance
John McWilliams, Q.C. Senior VP, General Counsel and Secretary
Canadian General Counsel Association
June 2006

Outstanding Individual Achievement
Dr. Randy Gossen, VP of SESR
Energy Institute
December 2006

Sustainability and Community

One of the Most Respected Companies in Alberta
Environment category
Alberta Venture Magazine
May 2006

Dow Jones Sustainability Index
Recognized as a global sustainability leader for the last six years by being included in this index
September 2006

Jantzi Research Award
Awarded for social and environmental performance
August 2006

Thanks a Million Award 2006
United Way of Calgary for raising over $1 million

Communications and Governance

National Award in Governance
The Conference Board of Canada
February 2007

Awards for North America's Best: IR Website, Disclosure Procedures, and Governance Practices
IR Global Rankings
February 2007

Awards of Excellence: Sustainable Development and Corporate Reporting in Oil and Gas
Canadian Institute of Chartered Accountants
December 2006

Oilweek Annual Report Award
Best Editorial/Graphic Design in senior oil and gas category
November 2006

Reserves before royalties, year-end pricing

	Oil & Gas Activities										Mining	
	International				United States		Canada			Total		Total Oil,
	Yemen	United Kingdom		Other Intl						Oil and		Gas and
(mmboe)	Oil	Oil	Gas	Oil	Oil	Gas	Oil	Gas	Bitumen	Gas	Syncrude [3]	Mining
Proved Reserves [1]												
Dec. 31, 2005	105	143	2	11	47	43	59	58	–	468	318	786
Extension, Discoveries and Conversions	4	23	2	30	2	5	1	10	–	77	13	90
Revisions	(8)	19	1	1	(8)	(3)	4	(1)	246	251	–	251
Production	(35) [4]	(6)	(2)	(2)	(7)	(6)	(7)	(6)	–	(71)	(7)	(78)
Dec. 31, 2006	**66**	**179**	**3**	**40**	**34**	**39**	**57**	**61**	**246**	**725**	**324**	**1,049**
Probable Reserves [1,2]												
Dec. 31, 2005	26	171	8	84	9	10	23	53	400	784	51	835
Extensions, Discoveries and Conversions	(3)	(24)	(1)	(30)	60	24	6	(7)	(246)	(221)	(5)	(226)
Revisions	(1)	5	1	5	–	(4)	(7)	(6)	–	(7)	–	(7)
Dec. 31, 2006	**22**	**152**	**8**	**59**	**69**	**30**	**22**	**40**	**154**	**556**	**46**	**602**
Proved + Probable Reserves [1,2]												
Dec. 31, 2005	131	314	10	95	56	53	82	111	400	1,252	369	1,621
Extensions, Discoveries and Conversions	1	(1)	1	–	62	29	7	3	(246)	(144)	8	(136)
Revisions	(9)	24	2	6	(8)	(7)	(3)	(7)	246	244	–	244
Production	(35) [4]	(6)	(2)	(2)	(7)	(6)	(7)	(6)	–	(71)	(7)	(78)
Dec. 31, 2006	**88**	**331**	**11**	**99**	**103**	**69**	**79**	**101**	**400**	**1,281**	**370**	**1,651**

Notes:

1 *We internally evaluate all of our reserves and have at least 80% of our proved reserves assessed by independent qualified consultants each year. Our reserves are also reviewed and approved by our Reserves Committee and our Board of Directors. Reserves represent our working interest before royalties at year-end constant pricing using SEC rules. Gas is converted to equivalent oil at a 6:1 ratio.*

2 *Probable reserves are determined according to SPE/WPC definitions. US investors should read the Cautionary Note to US Investors at the end of this report.*

3 *US investors should read the Cautionary Note to US Investors at the end of this report.*

4 *Production includes volumes used for fuel in Yemen.*

Booked and Beyond

We are a company focused on building a sustainable future and our reserve bookings are beginning to reflect this. In 2006, we invested $3.3 billion in oil and gas activities and added 341 mmboe of proved reserves, replacing our annual production more than four times over. In the past five years, we have invested approximately $13 billion and added 749 mmboe of proved reserves, replacing about 165% of our production.

In 2006, approximately 60% of our capital was invested in early stage and major development projects that added 300 mmboe of proved reserves, including 246 mmboe at Long Lake. These projects are characterized by multi-year investments where capital is invested, in some instances, years before reserves can be recognized. So measuring annual proved reserve additions against annual capital expenditures doesn't tell the whole story. To date, we have recognized 509 mmboe of proved reserves for our long cycle-time projects at Buzzard, Long Lake, Syncrude Stage 3 and CBM. And we have significant upside here with 315 mmboe of proved reserves. These projects are just beginning to add production, providing years of stable production and a solid foundation for growth.

Even more exciting is what we haven't yet booked. At year end, our proved and probable reserves totaled 1.7 billion boe. However, our total captured resource is significantly higher. Our booked reserves reflect little of the resource contained in our oil sands and CBM leases. We have over 700 sections of leases with CBM potential and an estimated 5.5 billion barrels of recoverable bitumen resource in the Athabasca oil sands. As we continue to develop these projects and demonstrate production performance, we expect to book significantly more reserves. In addition, we anticipate additional reserves from our undeveloped discoveries such as Golden Eagle and Knotty Head as we sanction commercial development. In total, our unrisked resource potential is estimated at 9.6 billion boe—indicating significant future capacity, growth and value.

Proved and Probable Reserves
1.7 billion boe

- Canada Bitumen (24%)
- Syncrude (23%)
- Canada (11%)
- United Kingdom (21%)
- Yemen (5%)
- Gulf of Mexico (10%)
- Other International (6%)

Unrisked Resource Potential
9.6 billion boe

- Canada Bitumen (52%)
- Syncrude (2%)
- Canada (7%)
- United Kingdom (8%)
- Gulf of Mexico (27%)
- Other International (4%)

Performance Review unaudited

(Cdn$ millions, except share and production data)	2006	2005	2004	2003	2002
Highlights					
Net Sales [1]	3,936	3,932	2,944	2,632	2,142
Cash Flow from Operations [2]	2,669	2,403	1,942	1,795	1,311
Per Common Share ($/share)	10.18	9.23	7.55	7.25	5.36
Net Income	601	1,140	793	578	409
Per Common Share ($/share)	2.29	4.38	3.08	2.33	1.67
Capital Expenditures	3,330	2,638	1,681	1,494	1,625
Business Acquisitions	78	–	2,583	–	–
Dispositions	27	911	34	293	49
Production [3,4]					
Production Before Royalties (mboe/d)	212	242	250	269	269
Production After Royalties (mboe/d)	156	173	174	185	176
Financial Position					
Working Capital	476	29	40	1,399	69
Property, Plant and Equipment, Net	11,739	9,594	8,643	4,550	4,944
Total Assets	17,156	14,590	12,383	7,717	6,665
Net Debt [5]	4,730	3,639	4,285	1,430	1,803
Long-Term Debt	4,673	3,687	4,259	3,089	2,596
Shareholders' Equity	4,636	3,996	2,867	2,075	1,590
Shares and Dividends					
Common Shares Outstanding (millions)	262.5	261.1	258.4	251.2	246.0
Number of Registered Common Shareholders	1,454	1,294	1,329	1,420	1,372
Closing Common Share Price (TSX) (Cdn$/share)	64.20	55.42	24.35	23.46	17.13
Dividends Declared per Common Share (Cdn$/share)	0.20	0.20	0.20	0.1625	0.15
Cash Flow from Operations [2]					
Oil and Gas					
Yemen	877	929	581	530	492
Canada	229	397	426	490	460
United States	573	667	700	623	190
United Kingdom	477	284	30	–	–
Other Countries	94	48	57	64	151
Marketing	432	138	100	126	45
Syncrude	240	223	183	105	129
	2,922	2,686	2,077	1,938	1,467
Chemicals	83	95	82	74	79
	3,005	2,781	2,159	2,012	1,546
Interest and Other Corporate Items	(254)	(335)	(196)	(208)	(219)
Income Taxes	(82)	(43)	(21)	(9)	(16)
Total Cash Flow from Operations	**2,669**	**2,403**	**1,942**	**1,795**	**1,311**

Notes:

1 Represents net sales from continuing operations.

2 Cash flow from operations is defined as cash generated from operating activities before changes in non-cash working capital and other.

3 Production is Nexen's working interest share and includes our share of production from Syncrude.

4 Natural gas is converted at 6 mcf per equivalent barrel of oil.

5 Net debt is defined as long-term debt and short-term borrowings less cash and cash equivalents.

For more historical information, view our Statistical Supplement at www.nexeninc.com or contact Investor Relations: 403.699.5821 or investor_relations@nexeninc.com.

Performance Review unaudited

	2006	2005	2004	2003	2002
Production Before Royalties					
Crude Oil and NGLs (mbbls/d)					
Yemen	92.9	112.7	107.3	116.8	118.0
Canada	20.0	29.2	36.2	46.3	56.3
United States	17.0	22.2	30.0	28.3	9.9
United Kingdom	16.9	12.6	1.5	–	–
Australia	–	–	2.7	6.1	12.8
Other Countries	6.3	5.6	5.3	5.4	8.9
Syncrude	18.7	15.5	17.2	15.3	16.6
	171.8	197.8	200.2	218.2	222.5
Natural Gas (mmcf/d)					
Canada	108	124	146	158	167
United States	111	116	148	145	112
United Kingdom	20	23	3	–	–
	239	263	297	303	279
Total Production Before Royalties (mboe/d)	**212**	**242**	**250**	**269**	**269**
Production After Royalties					
Crude Oil and NGLs (mbbls/d)					
Yemen	51.8	60.6	53.5	57.5	55.8
Canada	15.8	22.6	28.2	35.4	43.4
United States	15.0	19.6	26.5	25.0	8.2
United Kingdom	16.9	12.6	1.5	–	–
Australia	–	–	2.5	5.6	10.3
Other Countries	5.7	5.1	4.7	4.6	5.2
Syncrude	16.9	15.3	16.6	15.2	16.5
	122.1	135.8	133.5	143.3	139.4
Natural Gas (mmcf/d)					
Canada	91	101	115	125	128
United States	94	99	126	122	93
United Kingdom	20	23	3	–	–
	205	223	244	247	221
Total Production After Royalties (mboe/d)	**156**	**173**	**174**	**185**	**176**
Oil and Gas Cash Netback Before Royalties [1] ($/boe)					
Yemen	26.35	22.56	14.99	12.58	11.59
Canada	22.87	25.46	21.24	19.46	15.67
United States	40.42	45.85	35.35	32.48	19.30
United Kingdom	55.53	42.93	39.19	–	–
Australia	–	–	14.28	21.10	22.66
Syncrude	37.86	43.34	31.07	20.92	22.43
Other Countries	57.71	49.18	35.82	25.06	16.27
Company-Wide Oil and Gas	**32.75**	**30.57**	**22.66**	**19.24**	**15.06**

Note:

1 Defined as average sales price less royalties and other, operating cost and in-country taxes in Yemen. Calculation details can be found in the Statistical Supplement on our website.

Executive Management

Charles W. Fischer
President and
Chief Executive Officer

Marvin F. Romanow
Executive Vice President
and Chief Financial Officer

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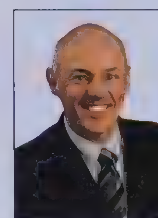
Senior Vice President,
Human Resources and
Corporate Services

John B. McWilliams, Q.C.
Senior Vice President,
General Counsel
and Secretary

Laurence Murphy
Senior Vice President,
International Oil
and Gas

Douglas B. Otten
Senior Vice President,
United States Oil
and Gas



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Canadian Oil
and Gas

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Vice President,
Energy Marketing

Kim McKenzie
Vice President,
Information Technology

Gary H. Nieuwenburg
Vice President,
Synthetic Crude

Kevin J. Reinhart
Vice President,
Corporate Planning and
Business Development

Michael J. Harris
Controller

Una M. Power
Treasurer

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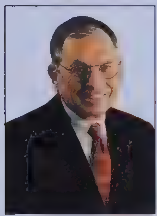
Chair of the Board
Calgary, Alberta,
Canada

Charles W. Fischer
President and CEO
Calgary, Alberta,
Canada

Dennis G. Flanagan
Calgary, Alberta,
Canada



David A. Hentschel
Tulsa, Oklahoma,
United States

S. Barry Jackson
Calgary, Alberta,
Canada

Kevin J. Jenkins
Calgary, Alberta,
Canada

The Honourable A. Anne McLellan, P.C.
Edmonton, Alberta,
Canada

Eric P. Newell, O.C.
Edmonton, Alberta,
Canada

Thomas C. O'Neill
Toronto, Ontario,
Canada

Richard M. Thomson, O.C.
Toronto, Ontario,
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John M. Willson
Vancouver,
British Columbia,
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Annual General and Special Meeting

11:00 a.m. M.T.
Thursday, April 26, 2007
Fairmont Palliser Hotel
Calgary, Alberta, Canada

Expected Earnings Release Dates

Q1 April 26, 2007
Q2 July 12, 2007
Q3 October 24, 2007
Q4 February 14, 2008

Stock Symbol—NXY

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Preferred Securities

7.35% Subordinated Notes
TSX—NXY.PR.U
NYSE—NXYPRB

Common Share Transfer Agent and Registrars

CIBC Mellon Trust Company
Calgary, Toronto, Montreal and Vancouver

Mellon Investor Services, LLC
New York, NY

Dividend Reinvestment Plan

The offering circular (and for US residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or at www.cibcmellon.com.

Auditors

Deloitte & Touche LLP
Calgary, Alberta, Canada

Website

Visite our website, www.nexeninc.com, for additional information including news releases, investor presentations, quarterly reports, conference call scripts, our ethics policy and more.

Other Reports

Check out our investor toolkit at www.nexeninc.com/investors to view our Proxy Circular, Sustainability Report and Statistical Supplement. Alternatively, hard copies may be ordered by calling 403.699.5931.

Operating Entities

Canada
Nexen Oil Sands Partnership

United States
Nexen Petroleum Offshore U.S.A. Inc.
Nexen Petroleum U.S.A. Inc.

International
Canadian Nexen Petroleum East Al Hajr Ltd.
Canadian Nexen Petroleum Yemen
Nexen Ettrick U.K. Limited
Nexen Exploration Norge AS
Nexen Exploration U.K. Limited
Nexen Petroleum Colombia Limited
Nexen Petroleum Nigeria Limited
Nexen Petroleum U.K. Limited

Marketing
Nexen Energy Marketing Europe Limited
Nexen Energy Marketing London Limited
Nexen Marketing
Nexen Marketing International Ltd.
Nexen Marketing Singapore Pte. Ltd.
Nexen Marketing U.S.A. Inc.

Chemicals
Canexus Chemicals Canada Limited Partnership
Canexus U.S. Inc.
Canexus Química Brasil Ltda.

Conversions

Natural gas is converted at 6 mcf per equivalent barrel of oil.

Dollar Amounts

In Canadian dollars unless otherwise stated.

Feedback: Please email your feedback to annual_report@nexeninc.com or phone 403.699.5821.

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Chair of the Board

Charles W. Fischer
President and Chief Executive Officer

Marvin F. Romanow
Executive Vice President and Chief Financial Officer

Nancy F. Foster
Senior Vice President, Human Resources and Corporate Services

John B. McWilliams, Q.C.
Senior Vice President, General Counsel and Secretary

Laurence Murphy
Senior Vice President, International Oil and Gas

Douglas B. Otten
Senior Vice President, United States Oil and Gas

Roger D. Thomas
Senior Vice President, Canadian Oil and Gas

Gary H. Nieuwenburg
Vice President, Synthetic Crude

Kevin J. Reinhart
Vice President, Corporate Planning and Business Development

Michael J. Harris
Controller

Una M. Power
Treasurer

Rick C. Beingessner
Assistant Secretary

Sylvia L. Groves
Assistant Secretary

For more information on our officers and directors, please see Item 10 in our Form 10-K.

Forward-Looking Statements

Certain statements in this report constitute "forward-looking statements" within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such statements are generally identifiable by the terminology used such as "intend", "plan", "expect", "estimate", "budget", "outlook" or other similar words, and include statements relating to future production associated with our coalbed methane, Aspen, Long Lake, Syncrude, North Sea, West Africa and other projects.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas and chemicals products; the ability to explore, develop, produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; foreign-currency exchange rates; economic conditions in the countries and regions where Nexen carries on business; actions by governmental authorities including increases in taxes or royalties, changes in environmental and other laws and regulations; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; and political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend on its assessment of the future considering all information then available. Any statements as to possible future prices, future production levels, future cost recovery oil revenues from our Yemen operations, future capital expenditures and their allocation to exploration and development activities, future asset dispositions, future sources of funding for our capital program, future debt levels, future cash flows, future drilling of new wells, ultimate recoverability of reserves, expected finding and development costs, expected operating costs, future demand for chemicals products, future expenditures and future allowances relating to environmental matters and dates by which certain areas will be developed or will come on stream, and changes in any of the foregoing are forward-looking statements.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Readers should also refer to Items 7 and 7A in our 2006 Annual Report on Form 10-K for further discussion of the risk factors.

Cautionary Note to US Investors—The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to discuss only proved reserves that are supported by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this report, we may refer to "recoverable reserves", "probable reserves" and "recoverable resources" which are inherently more uncertain than proved reserves. These terms are not used in our filings with the SEC. Our reserves and related performance measures represent our working interest before royalties, unless otherwise indicated. Please refer to our Annual Report on Form 10-K for further reserve disclosure.

In addition, under SEC regulations, the Syncrude oil sands operations are considered mining activities rather than oil and gas activities. Production, reserves and related measures in this report include results from the Company's share of Syncrude.

Cautionary Note to Canadian Investors—Nexen is required to disclose oil and gas activities under *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. However, the Canadian securities regulatory authorities (CSA) have granted us exemptions from certain provisions of NI 51-101 to permit US style disclosure. These exemptions were sought because we are a US Securities and Exchange Commission (SEC) Registrant and our securities regulatory disclosures, including Form 10-K and other related forms, must comply with SEC requirements. Our disclosures may differ from those Canadian companies who have not received similar exemptions under NI 51-101.

Please read the "Special Note to Canadian Investors" in Item 7A in our 2006 Annual Report on Form 10-K, for a summary of the exemption granted by the CSA and the major differences between SEC requirements and NI 51-101. The summary is not intended to be all-inclusive or to convey specific advice. Reserve estimation is highly technical and requires professional collaboration and judgment. The differences between SEC requirements and NI 51-101 may be material.

Our probable reserves disclosure applies the Society of Petroleum Engineers/World Petroleum Council (SPE/WPC) definition for probable reserves. *The Canadian Oil and Gas Evaluation Handbook* states there should not be a significant difference in estimated probable reserve quantities using the SPE/WPC definition versus NI 51-101.

In this report, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

The Next Step

Long Lake: On Stream in 2007
Begin producing bitumen and
start upgrading to synthetic oil

nexen

Nexen is a Canadian-based global energy company growing value responsibly.

see the VALUE

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